

## Chapter 7

# ELECTRICITY SUPPLY TECHNOLOGIES

## 7.1 INTRODUCTION

The electricity industry has many supply-side options at its disposal to reduce or offset carbon dioxide emissions from electricity production by the year 2010. One of these options, reconfiguring the generation mix to reflect a \$50/tonne charge for carbon, was discussed in Chapter 6. We labeled this option “carbon-ordered dispatching” because it involves the same technologies that were considered in the AEO97 reference case. Electricity was redispatched from the existing generation mix, and the construction and retirement of power plants also changed, but no new technologies were introduced. Chapter 7 considers other electricity supply technology options, including:

Repowering coal-based power plants with natural gas;

Implementing renewable electricity technologies;

Improving efficiency in generation and transmission and distribution (T&D) systems;

Extending the life of existing nuclear plants; and

Constructing new power plants using advanced coal technologies.

Each of these options is assessed independently. Because interactions among the options are not taken into account, there is a likely possibility of double-counting with respect to the actual emissions reduction potential.

The viability and costs of these supply options in 2010 are based on the assumption that the electricity grid is transformed by the carbon-ordered dispatching that occurs under the “high-efficiency/low-carbon” (HE/LC) scenario, as described in Chapter 6. Thus, since we assume that considerable decarbonization has already taken place, this chapter addresses the question: What additional supply technology options now make sense in a scenario in which carbon has acquired a value of \$50/tonne? We conclude by discussing the significant contribution that renewable energy technologies can make by the year 2020.

## 7.2 REPOWERING COAL-BASED POWER PLANTS WITH NATURAL GAS

The conversion of existing coal-fired power plants to operate on natural gas (via repowering) is one option to significantly increase the efficiency of power generation and reduce carbon emissions in the U.S. electric power sector.<sup>1</sup> Natural gas is a less carbon-intensive fuel and its use also reduces emissions of the following criteria air pollutants: sulfur dioxide (SO<sub>2</sub>), nitrogen oxide (NO<sub>x</sub>), total suspended particulates (TSP), and hazardous air pollutants (HAPs). Our analysis shows that natural gas combined cycle (NGCC) is a cost-effective power generation technology and carbon emission reduction option. Depending upon assumptions regarding the differential in the delivered price between natural gas and coal, the price of carbon permits, and environmental externality values for criteria air pollutants, we found that carbon emissions of up to 238 MtC could be reduced annually through repowering.

### 7.2.1 Repowering Approaches

The simplest repowering approach is *site repowering*, where the existing power plant site is reused with an entirely new NGCC system. Cost and performance data for the General Electric “H” frame turbine was used; this class of turbine will be the most efficient in the post-2000 period, with the lowest cost per kilowatt of capacity. While site repowering provides the highest cycle efficiency (since none of the existing boiler island equipment is reused), it also requires a greater capital investment (see Appendix G-1).

The more conventional approach is referred to as *steam turbine repowering*. In this case, a new gas turbine and heat recovery steam generator (HRSG) are integrated with the existing steam turbine and auxiliary equipment from the coal plant. Due to age of equipment and the fact that the steam turbine was designed for linkage with a coal-fired boiler, the efficiency of a *repowered* steam turbine plant would be lower than at a *site repowered* plant. The steam turbine repowering option has a higher operating cost (due to the lower efficiency) but a lower capital cost (see Appendix G-1).

The cost-effectiveness (\$/tC) of both repowering options was examined for all coal-fired power plants greater than 50 megawatts (MW).<sup>2</sup> Included in the cost calculation were the cost of repowering, hook-up, and transmission. We analyzed the site repowering results for the two alternative gas/coal price differentials: \$0.72 and \$1.18 per million Btu (MBtu)<sup>3</sup>, three price ranges for carbon permits (<\$50/tonne, \$50-100/tonne, and \$101-150/tonne), and three environmental externality values for SO<sub>2</sub> and NO<sub>x</sub> (none, low, and high). In addition, a sensitivity analysis was performed to examine the impact on cost-effectiveness if additional natural gas pipeline infrastructure (hook-up and transmission) were not needed to ensure gas deliverability to repowered plants. This sensitivity analysis (referred to as the “no additional transmission cost” case) was conducted only for those power plants that are currently connected to the natural gas pipeline network (i.e., dual-fuel). Appendix G-3 contains a complete description of the methodological steps and key data parameters.

The analytical approach was static in that the cost of repowering was computed for each candidate power plant but the analysis did not optimize unit/plant production cost, dispatch, or system load. Moreover, for the steam repowering case, the largest steam turbine (not each individual steam turbine) at the plant was repowered to generate the equivalent of 1995 plant output (kilowatt-hours, kWh), since this is both more economic and consistent with industry practice than repowering each turbine. Lastly, the gas delivery infrastructure costs (hook-up and transmission) were derived assuming (1) no excess capacity in the current delivery system, and (2) that if such a fuel-switching strategy were implemented, the natural gas pipeline industry would build capacity (even if done incrementally) to meet the total estimated gas requirements of repowering all candidate plants and allocate appropriate delivery costs to each repowered plant. Assumptions regarding gas deliverability are described below in Section 7.2.2.2.

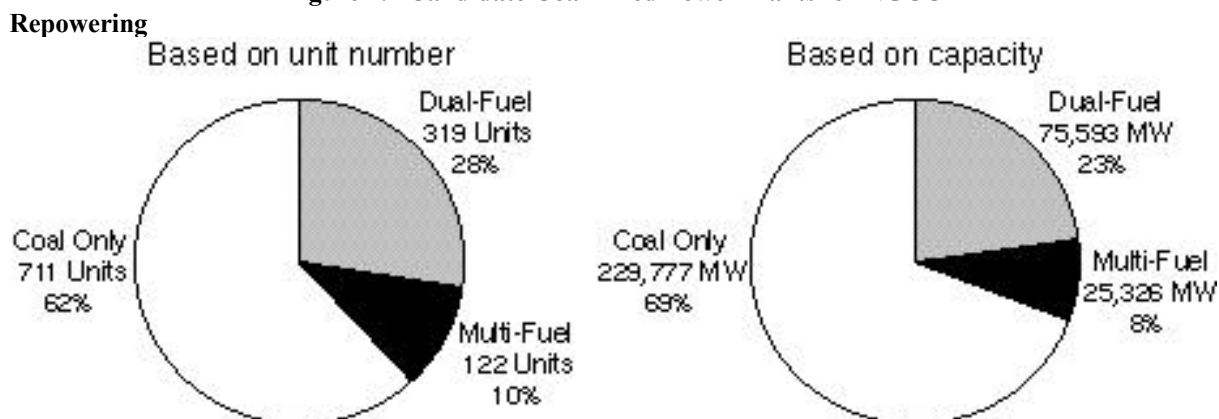
### 7.2.2 Repowering Issues

In 1995, there was 335 GW of coal-fired capacity at 404 power plants in the United States. Figure 7.1 indicates that this capacity was comprised of:

319 dual-fuel units (units that can burn both coal and natural gas),

122 multi-fuel units (coal-fired units at sites with natural gas or petroleum units), and

711 coal-fired units (units at coal-only plant sites).

**Figure 7.1 Candidate Coal-Fired Power Plants for NGCC**

These categories reflect differences in the investment cost of conversion and deliverability of natural gas (i.e., those plant sites consuming gas in 1995 would have a natural gas pipeline connection, thereby resulting in a lower hookup cost.)

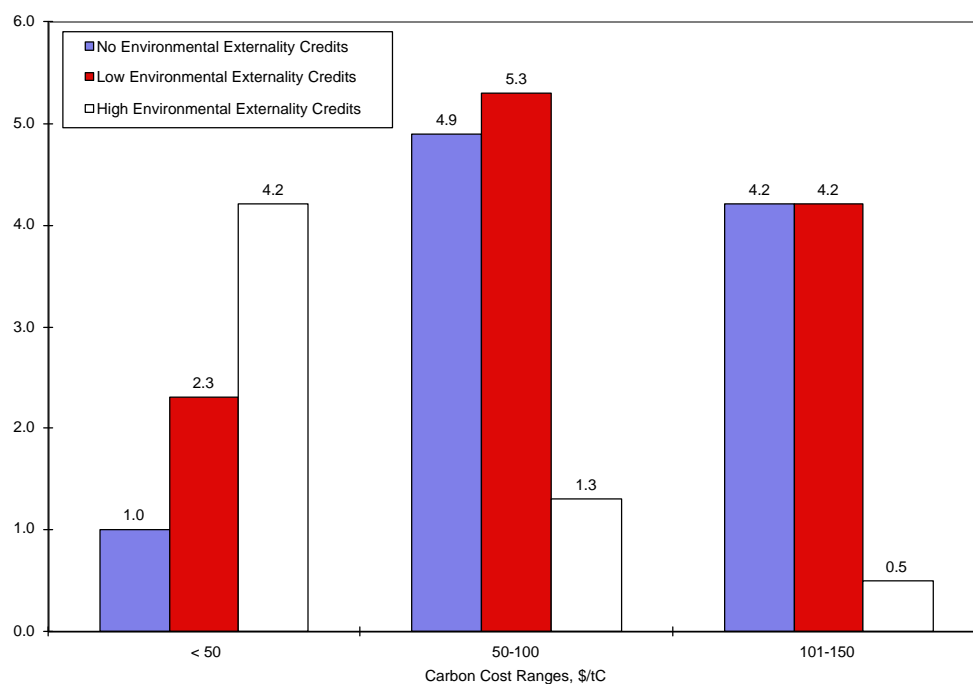
### 7.2.2.1 Increase in Natural Gas Demand

Utility gas consumption in 1995 was 3.5 trillion cubic feet (TCF). Figures 7.2 and 7.3 show the increases in natural gas demand from this base that would result from either site or steam turbine repowering for each of three cost-effectiveness values: less than \$50/tC, \$50-100/tC, and greater than \$150/tC. The increase in gas demand ranges from 1.0 TCF (<\$50/tC) to 4.9 TCF (\$50-100/tC) in the low gas/coal price differential case without externalities. This quantity of gas for repowered plants represents 29% and 140% increases in 1995 utility gas consumption, respectively.

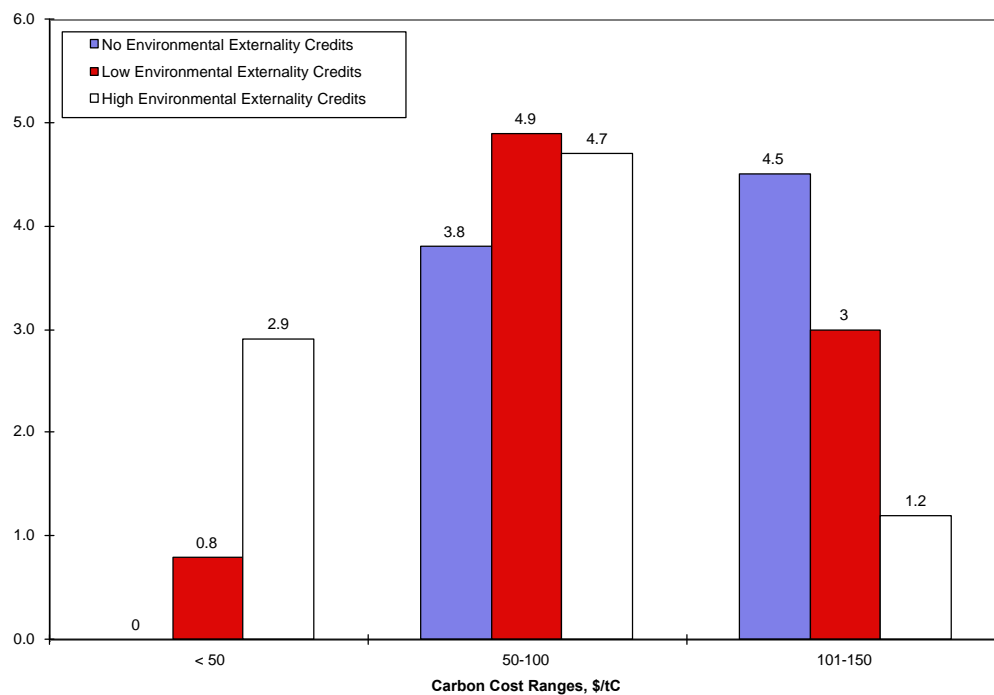
If all the candidate coal-fired power plants were repowered with NGCC, natural gas demand in the utility sector would increase by 9.0 TCF/yr (site repowering) or 9.4 TCF/yr (steam turbine repowering) to either 12.5 TCF/yr or 12.9 TCF/yr, respectively, an increase of over 250% compared to current consumption levels.

The potential gas price increase resulting from NGCC repowered plants was not analyzed in this study. Only the current and projected gas/coal price differentials expected under AEO97 were included in the cost analysis. However, EIA has prepared a preliminary estimate; they found that an 11 TCF increase in demand would increase natural gas prices by \$3.09/MBtu over 20 years (1995-2015), if coal-fired power plants were converted to natural gas when scheduled for life extension/refurbishment and there was considerable demand-side energy-efficiency investment.

**Figure 7.2 Incremental Increase in Gas Consumption Resulting from Coal to Gas Conversion with Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)**



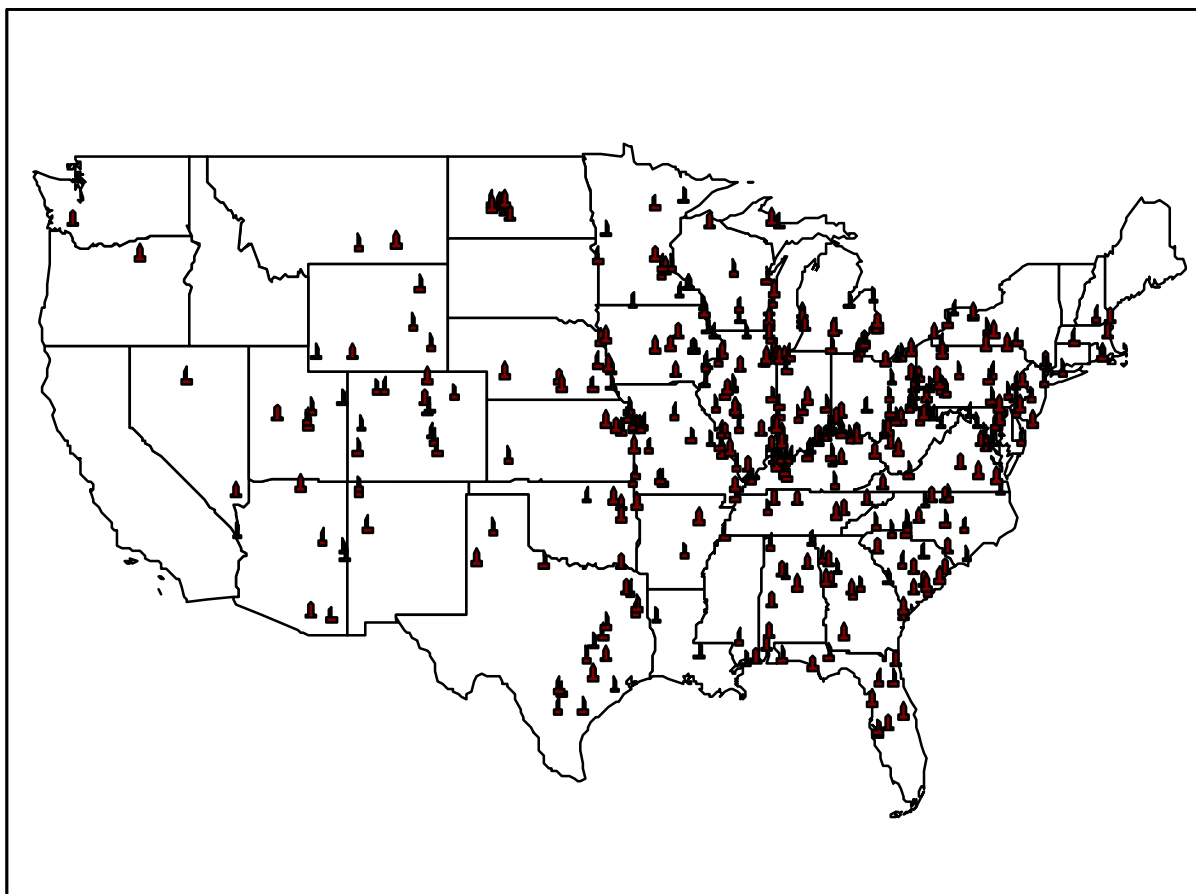
**Figure 7.3 Incremental Increase in Gas Consumption Resulting from Coal to Gas Conversion with Constant 2010 Gas/Coal Price Differential (\$1.18/MBtu)**



### 7.2.2.2 Gas Deliverability

The spatial distribution of the initial 404 candidate plants is depicted in Figure 7.4. Some of the candidate plants were not considered for repowering since they were (1) not considered economic by EIA, or (2) determined to be unnecessary due to reductions in demand arising from end-use efficiency improvements.<sup>2</sup> Most of the plants are located in the Mid-Atlantic, South Atlantic, Midwest, and Plains regions. While these are also primary gas-consuming regions served by major trunk lines, many industry experts believe there is limited unused or underutilized capacity in the current 1.2 million mile pipeline system (transmission – 264,900 miles; distribution – 935,000 miles; field – 62,200 miles). Since this capacity is necessary to accommodate peak winter demand and non-utility growth, it is of little value to power plants considering conversion, since these power plants require firm pipeline commitments.

**Figure 7.4 Location of Candidate Plants for Coal/Gas Repowering in the U.S.**



Due to the potentially significant increase in utility gas demand that could result from repowering (either site or steam turbine) coal-fired power plants, and the uncertainties regarding when repowering would take place, new pipeline capacity sufficient to serve all candidate plants was developed to ensure deliverability. A detailed assessment was performed (using a geographical information system, GIS) to compute the distance of each candidate power plant to its nearest trunk line. Cost estimates were derived for the cost of upgrading the lines to meet the increased gas demands (see Appendix G-4).<sup>4</sup> Table 7.1 summarizes the distance of the candidate plants to their closest production zone.

The requirement to add new pipeline capacity could affect the attractiveness of repowering as a carbon mitigation strategy. During 1994 and 1995, 1,200 to 1,500 miles of new pipeline were added to the system.

According to Federal Energy Regulatory Commission (FERC) filings of pipeline projects, there are a considerable number of new pipelines and pipeline expansions that have been proposed, some of which are still pending approval. While mileage is not included with each filing, in the regions of concern (Central, Midwest, Northeast, and Southeast), more than 8,200 miles of pipe is projected to be added; this level of expansion is greater than the 1994-95 rate of addition. However, it is not known how long it will take to complete these proposed pipelines. Consequently, an accurate assessment of the ability to increase the rate of pipeline expansion/construction could not be estimated as a part of this study.

**Table 7.1 Plant Distance from Production Zone**

Range (Miles)	Dual-Fuel		Multi-Fuel		Coal Only		Total	
	# Units	%	# Units	%	# Units	%	# Units	%
60 - 440	48	37	5	12	55	22	108	26
440 - 620	33	25	8	19	64	26	105	25
620 - 890	30	23	15	35	59	24	104	25
890-1,480	19	15	15	35	67	27	101	24
Total	130	100	43	100	245	100	418	100

### 7.2.3 Emissions Reductions

Based on our analysis, repowering of coal-fired power plants with NGCC is a cost-effective carbon reduction strategy. Tables 7.2-7.4 summarize the site repowering results for the two alternative gas/coal price differentials: \$0.72 and \$1.18 per million Btu (MBtu), three price ranges for carbon permits (<\$50/tonne, \$50-100/tonne, and \$101-150/tonne), and three environmental externality values for SO<sub>2</sub> and NO<sub>x</sub> (none, low, and high). The price differential of \$0.72/MBtu represents the 1995 gas/coal price differential held constant, while \$1.18/MBtu is EIA's forecasted price differential for the year 2010.<sup>5,6</sup> In addition to the "no externalities" case, two alternative market values were used for SO<sub>2</sub> and NO<sub>x</sub>: low externalities represent \$0 per ton of SO<sub>2</sub> and \$700 per ton of NO<sub>x</sub>; high externalities represent \$100 per ton of SO<sub>2</sub> and \$1400 per ton of NO<sub>x</sub>.

As can be seen in Table 7.2, given a carbon permit price of less than \$50/tC and a gas/coal price differential of \$0.72/MBtu, 30 to 119 MtC could be removed via NGCC site repowering, depending upon externality assumptions. When the price differential increases to \$1.18/MBtu, 0 to 83 MtC could be removed from utility emissions. Consequently, we see that a increase of \$0.46/MBtu in the price differential decreases carbon reductions from NGCC repowering by approximately 30 MtC. Although the disaggregated data are not presented, most of the carbon reduction in the <\$50/tC range actually occurs in the \$25-50/tC range.

An ancillary benefit of switching from coal to gas and improving conversion efficiency is reduction in SO<sub>2</sub> and NO<sub>x</sub>, two criteria pollutants. At the <\$50/tC level, approximately 50% of the SO<sub>2</sub> and NO<sub>x</sub> would be removed (depending on the externality value); at \$50-100/tC and higher almost all the remaining coal-fired SO<sub>2</sub> and NO<sub>x</sub> emissions would be eliminated. If all the candidate plants were repowered, almost all of the SO<sub>2</sub> and most of the NO<sub>x</sub> would be removed.

The economic value of the SO<sub>2</sub> and NO<sub>x</sub> emissions reductions that would result from repowering of the plants was also assessed in this study. Using the methodology described in Appendix G-2, SO<sub>2</sub> was valued from \$0-100/ton; NO<sub>x</sub> was valued at from \$700-1400/ton. These values were used as the basis for the environmental externality credits to offset the investment cost of repowering.

**Table 7.2 Summary Statistics: Coal to Gas Repowering with a Carbon Permit Price of <\$50/tonne**

<i>Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)</i>					
Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO <sub>2</sub> Removed (Mt)	Incremental NO <sub>x</sub> Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	30.3	0.5	0.7	26.8	1.0
Low	66.0	1.2	1.4	63.3	2.3
High	118.6	4.0	2.6	122.6	4.2
<i>Gas/Coal Price Differential in 2010 (\$1.18/MBtu)</i>					
Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO <sub>2</sub> Removed (Mt)	Incremental NO <sub>x</sub> Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	0	0	0	0	0
Low	23.6	0.3	0.6	20.2	0.8
High	83.4	2.5	1.9	83.3	2.9

\* Two alternative market values were used for SO<sub>2</sub> and NO<sub>x</sub>: low externalities represent \$0 per ton of SO<sub>2</sub> and \$700 per ton of NO<sub>x</sub>; high externalities represent \$100 per ton of SO<sub>2</sub> and \$1400 per ton of NO<sub>x</sub>.

\*\*TCF = trillion cubic feet

**Table 7.3 Summary Statistics: Coal to Gas Repowering with a Carbon Permit Price of \$50-100/tonne**

<i>Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)</i>					
Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO <sub>2</sub> Removed (Mt)	Incremental NO <sub>x</sub> Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	134.6	4.9	2.7	147.3	4.9
Low	140.4	6.7	2.8	165.6	5.3
High	106.7	5.0	1.8	130.8	4.2
<i>Gas/Coal Price Differential in 2010 (\$1.18/MBtu)</i>					
Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO <sub>2</sub> Removed (Mt)	Incremental NO <sub>x</sub> Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	109.6	2.5	2.2	108.9	3.8
Low	134.1	5.0	2.7	146.4	4.9
High	123.9	5.5	2.3	147.6	4.7

\* Two alternative market values were used for SO<sub>2</sub> and NO<sub>x</sub>: low externalities represent \$0 per ton of SO<sub>2</sub> and \$700 per ton of NO<sub>x</sub>; high externalities represent \$100 per ton of SO<sub>2</sub> and \$1400 per ton of NO<sub>x</sub>.

\*\*TCF = trillion cubic feet

**Table 7.4 Summary Statistics: Coal to Gas Repowering with a Carbon Permit Price of \$101-150/tonne**

<i>Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)</i>					
Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO <sub>2</sub> Removed (Mt)	Incremental NO <sub>x</sub> Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	69.4	4.0	1.2	93.9	2.8
Low	31.0	1.6	0.5	43.8	1.3
High	13.1	0.6	0.2	20.9	0.5
<i>Gas/Coal Price Differential in 2010 (\$1.18/MBtu)</i>					
Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO <sub>2</sub> Removed (Mt)	Incremental NO <sub>x</sub> Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	117.2	6.6	2.3	148.4	4.5
Low	75.1	4.0	1.2	98.6	3.0
High	29.8	1.5	0.4	41.4	1.2

\* Two alternative market values were used for SO<sub>2</sub> and NO<sub>x</sub>: low externalities represent \$0 per ton of SO<sub>2</sub> and \$700 per ton of NO<sub>x</sub>; high externalities represent \$100 per ton of SO<sub>2</sub> and \$1400 per ton of NO<sub>x</sub>.

\*\*TCF = trillion cubic feet

#### 7.2.4 Cost-Effectiveness

Figure 7.5 portrays the cost-effectiveness of site repowering with NGCC and the corresponding cumulative carbon removed for the two alternative gas/coal price differentials when no environmental externalities are considered. With a price differential of \$0.72/MBtu, approximately 30 MtC can be removed for <\$50/tC, an

additional 135 MtC can be removed for \$51-100/tC, and an additional 77 MtC can be removed for >\$100/tC. When the price differential increases to \$1.18/MBtu, 0 MtC of carbon are removed at <\$50/tC, 110 MtC are removed at \$51-100/tC, and an additional 132 MtC are removed at >\$100/tC.

Figures 7.6 and 7.7 depict the effect of environmental externality credits for SO<sub>2</sub> and NO<sub>x</sub> on carbon cost-effectiveness. As mentioned above, in addition to the "no externalities" case, two alternative market values were used for SO<sub>2</sub> and NO<sub>x</sub>: low externalities represent \$0 per ton of SO<sub>2</sub> and \$700 per ton of NO<sub>x</sub>; high externalities represent \$100 per ton of SO<sub>2</sub> and \$1400 per ton of NO<sub>x</sub>. The rationale for these values is explained in Appendix G-3. Both Figures 7.6 and 7.7 (together with Tables 7.2 - 7.4) illustrate that the effect of the environmental externality credit is to shift the carbon cost curve downward and to the right causing more capacity (GW) and carbon removal (MtC) to occur at lower carbon permit price levels.

Because dual-fuel plants are already receiving natural gas (although at lower volumes than a repowered plant), a sensitivity analysis was conducted wherein no hook-up or transmission costs were incurred to deliver an increased quantity of natural gas to these repowered plant sites. This "no additional transmission cost case" is illustrated in Figures 7.8 and 7.9, which depict the two alternative gas/coal price differentials and include externality credits for site and steam turbine repowering. Since transportation costs comprise approximately 30% of the total investment cost, the carbon cost curves shift downward considerably when these costs are removed. In Figure 7.8, approximately 45 GW of coal-fired capacity can be repowered at <\$50/tC, removing 42 MtC of carbon, 1.2 Mt of SO<sub>2</sub> and 0.9 Mt of NO<sub>x</sub>. The amount of natural gas required by these repowered plants is 1.5 thousand cubic feet; approximately 50% of 1995 utility consumption.

The cost-effectiveness numbers derived in this study are optimistic. These numbers should be used with caution because they do not (or do not adequately) consider the following factors that will determine the ultimate cost-effectiveness of the coal-to-gas repowering:

Potential increase in gas prices from NGCC repowering,

Actual cost of repowering the candidate coal-fired power plants,

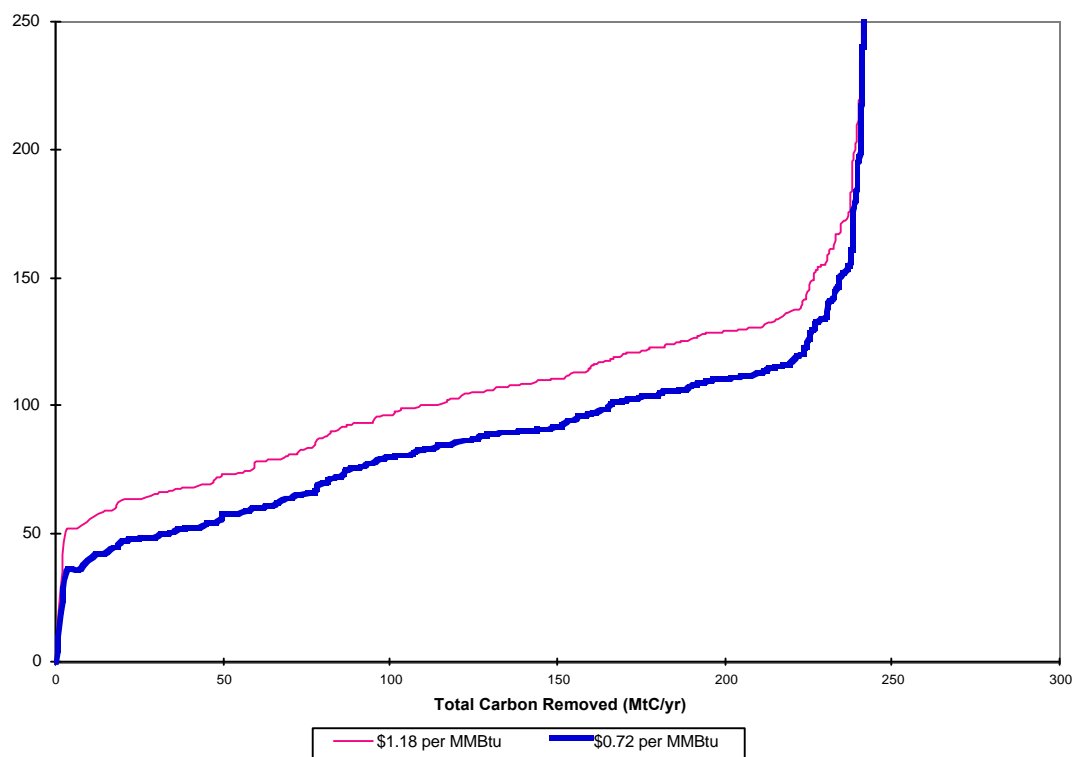
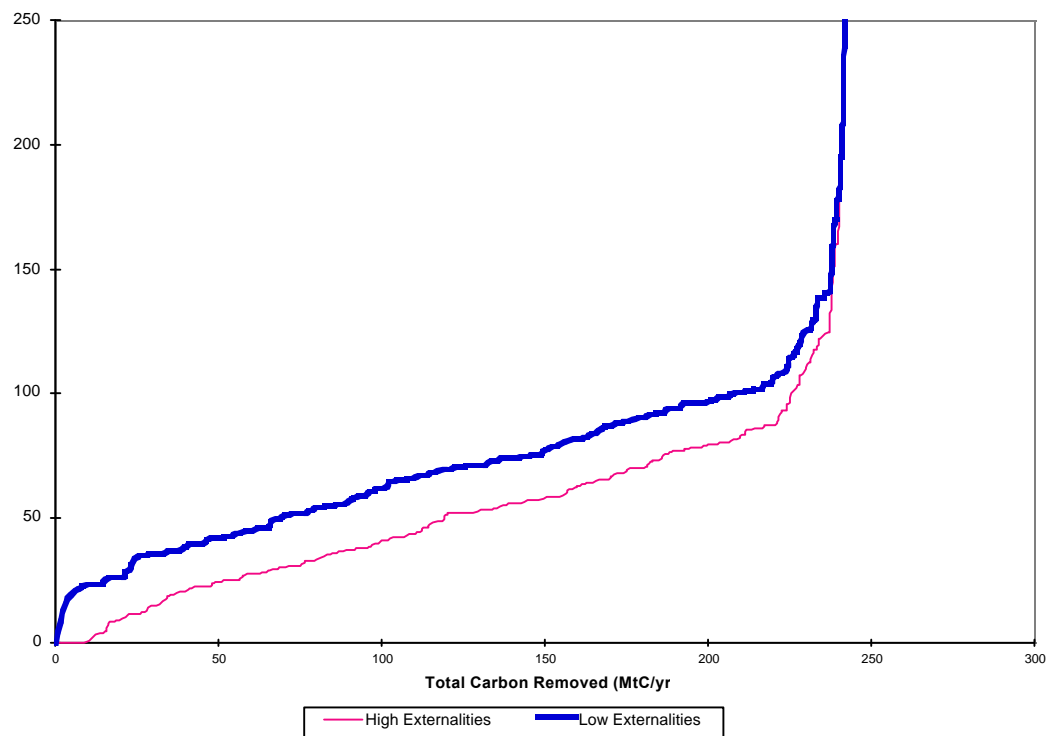
Excess transmission capacity, and/or economies of scale in delivering the required gas,

Capacity utilization of the converted plants,

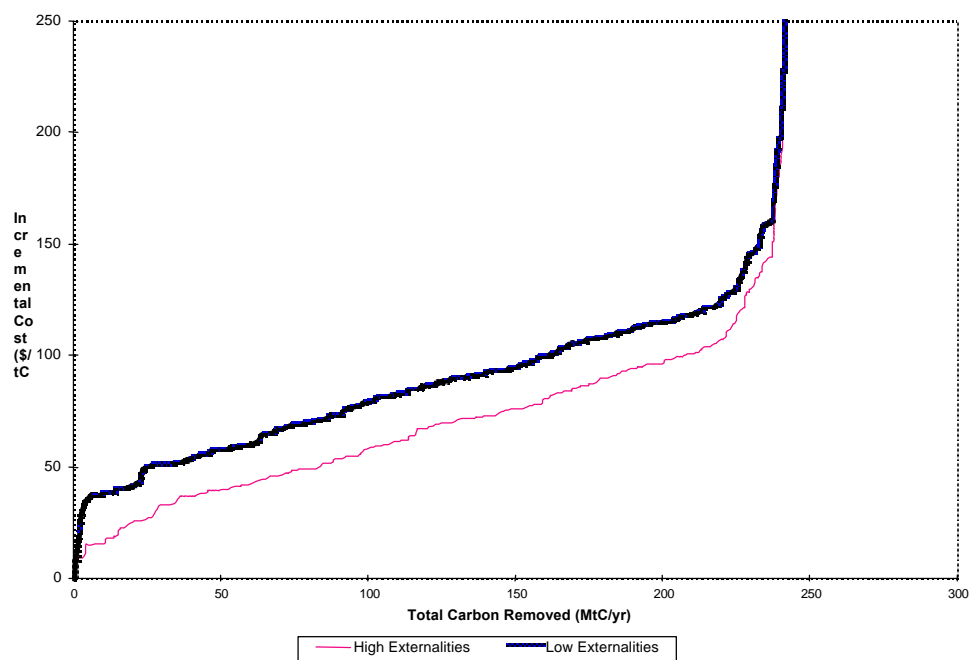
Costs associated with breaking long-term coal contracts, and

Other socioeconomic factors (e.g., differential state/federal tax effects, displaced coal miners).

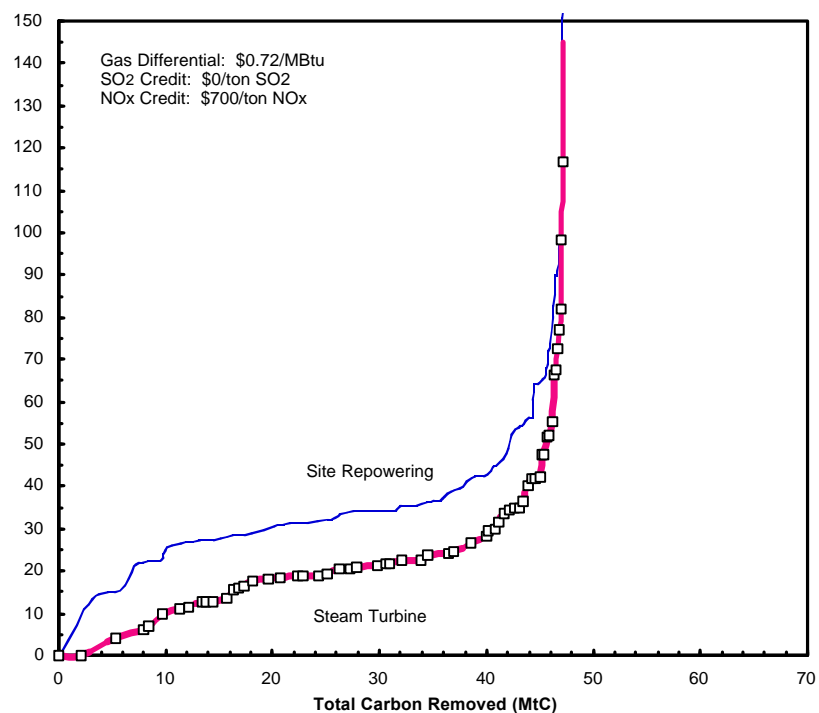
In addition, the effectiveness of repowering as a carbon control strategy will depend on whether and to what extent the converted plants are dispatched. If, because of the costs associated with conversion, the repowered plants are not dispatched or their utilization is minimized, the associated carbon reductions will depend on the fuels and technologies used at the plants dispatched ahead of the repowered plants.

**Figure 7.5 Carbon Curve for Coal/Gas Site Repowering: No Environmental Externality Credits****Figure 7.6 Carbon Curve for Coal to Gas Site Repowering: Effect of Environmental Externality Credits on Cost of Carbon Removal with Constant 1995 Gas/Coal Price Differential (\$0.72 MBtu)**

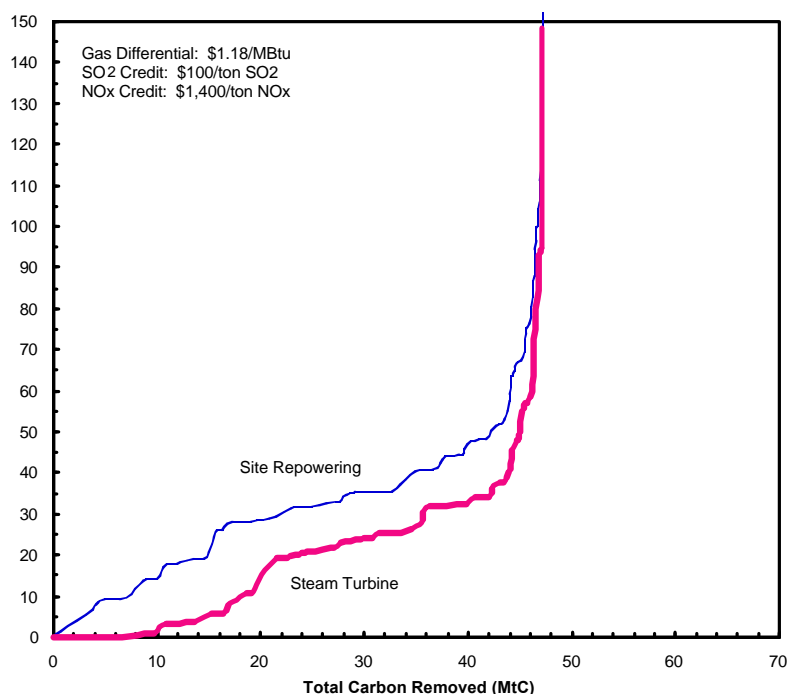
**Figure 7.7 Carbon Curve for Coal to Gas Site Repowering: Effect of Environmental Externality Credits on Cost of Carbon Removal with Gas/Coal Price Differential in 2010 (\$1.18 MBtu)**



**Figure 7.8 Carbon Curve for Partial Repowering<sup>7</sup>: Constant 1995 Gas/Coal Price Differential (\$0.72 MBtu) Low Environmental Externality Credits**



**Figure 7.9 Carbon Curve for Partial Repowering<sup>7</sup>: Constant 2010 Gas/Coal Price Differential (\$1.18 MBtu) High Environmental Externality Credits**



### 7.3 RENEWABLE ELECTRICITY TECHNOLOGIES

Over the long term, renewable energy technologies are likely to play a crucial role in limiting carbon emissions and global warming. While aggressive energy efficiency and fuel switching can reduce domestic carbon emissions to approximately 1990 levels by 2010, controlling or reducing carbon emissions beyond that date will require greater energy contributions from low-carbon technologies such as renewables. In other words, renewables will play an essential role in helping the United States to cut carbon emissions in the years beyond 2010.

Renewables will also make important contributions to both domestic and international carbon emission controls by 2010. Renewable technology contributions to domestic electricity and carbon savings in 2010 under the HE/LC scenario are summarized in Table 7.5.

**Table 7.5 Additions to Generating Capacity Electricity and Carbon Emission Reductions from Renewables for the HE/LC Case in 2010**

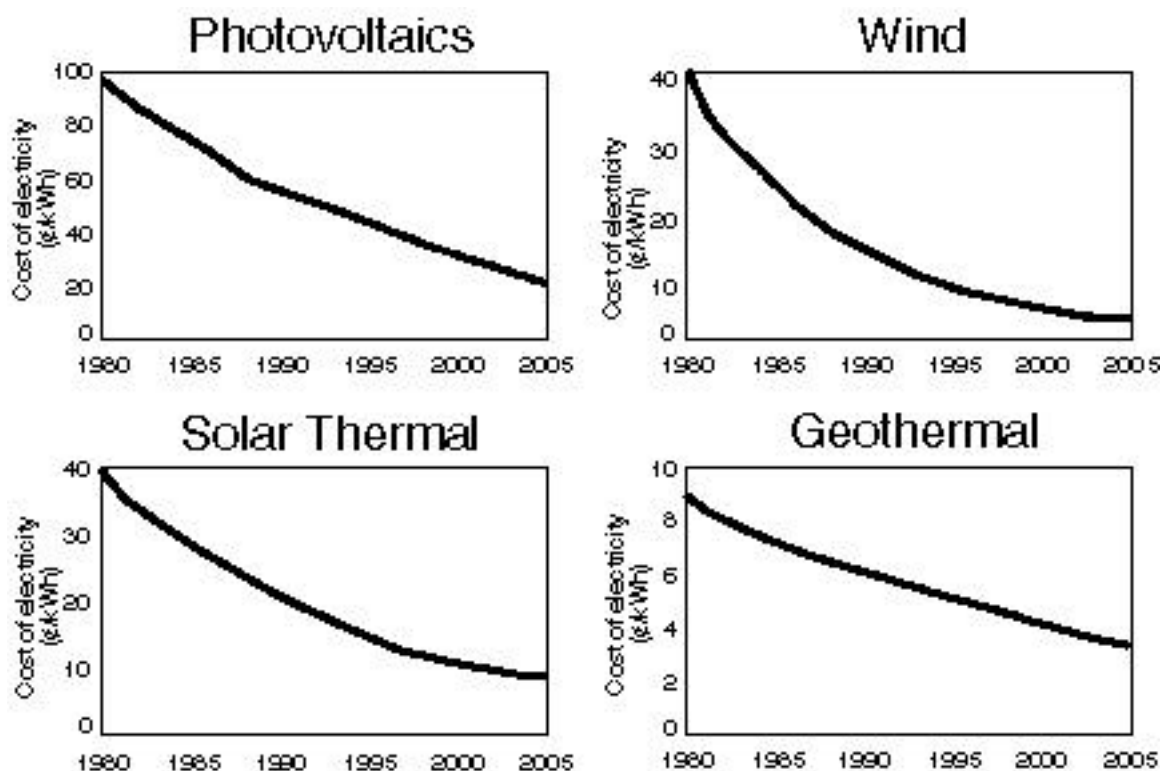
<b>Renewable Technology</b>	<b>Capacity Additions (GW)</b>	<b>Electricity (TWh)</b>	<b>Carbon Emission Reduction (MtC)<sup>a</sup></b>
<b>Included in Scenario:</b>			
Biomass Cofiring	8-12	58-88	16-24
Wind	8-23	28-81	6-20
Hydropower	10-16	23-35	3-5
Subtotal			25-49
<b>Excluded from Scenario:</b>			
Landfill Gas <sup>b</sup>	3-7	20-50	25-53
PV	3-5	6-10	1-2
Geothermal	6-14	47-110	6-16
Solar Thermal	0-2	0-6	0-1
Subtotal			32-72
<b>Total</b>	<b>38-79</b>	<b>182-380</b>	<b>57-121</b>

<sup>a</sup> These carbon emissions reductions represent the difference between the high-efficiency/low-carbon case and the business-as-usual forecast for 2010.

<sup>b</sup> The carbon emission reduction in this case represents the equivalent derived from the prevention of the methane release coupled with its radiation-trapping properties.

This section examines the potential for renewable electricity technologies to reduce U.S. carbon emissions. The contributions of renewables in various end-use sectors, such as transportation, are discussed in other chapters in this report.

Renewables are in the midst of a major, long-term transition, from being “advanced technologies” with only a peripheral market role to becoming mainstream “technologies of choice” in the energy marketplace early in the next century. One clear marker of this transition is the changing cost of electricity from renewable power technologies. Figure 7.10 displays these costs for the period from 1980 to 2005, based on both historical data and recent projections (Office of Utility Technologies, 1997).

**Figure 7.10 Historical and Projected Costs of Electricity from Four Renewable Power Technologies**

The pace and timing of this transition is difficult to project, however, because it is strongly dependent on such variables as the progress made through research and development, the evolution of energy economy policies, and the magnitude and impact of consumer interest in “green” energy. For example, under the \$50/MtC cost-of-carbon scenario assumed in this study, the adoption of wind power in the United States is likely to increase rapidly on an economic basis. In addition, increasing attention is being focused on consumer interest in green energy. As the electric utility sector moves toward competitive markets, consumers probably will have the option of purchasing power that is environmentally cleaner.

The rate of change will impact the role of renewables in 2010 at least as much as the specific energy contribution of renewables in that year. Therefore, this section discusses the trends as well as the predicted contributions of renewables to the energy supply and to carbon emission reductions in 2010.

A thorough analysis of the role of renewables in 2010, which captures the complexity of their transition, has not been conducted as a part of this study. Instead, this section presents analyses of a few renewable technologies whose role is likely to be quite significant by 2010, and includes a general discussion of the other renewable technologies. A more thorough analysis of the relationship between renewables and reductions in carbon emissions over a longer time frame is the subject of a future study.

Thus, this section discusses the role of renewables in two time frames: (1) developments and contributions by 2010, and (2) the long-term outlook.

### 7.3.1 Renewable Electricity in 2010

As stated earlier, renewable electric technologies will make important contributions to carbon emission reductions in 2010 in the context of a policy that imposes a \$50/tonne cost on carbon emissions. Estimates of

those contributions are presented here. While the scope of this study did not include a thorough and systematic analysis of this issue, the estimates given are based on a number of directly relevant studies. These include, in particular, carefully developed performance and cost projections for renewable electric technologies (Office of Utility Technologies, 1997) and projections of future market penetrations of these technologies (Office of Energy Efficiency and Renewable Energy, 1997).

The potential of biomass cofiring was assessed because that technology provides an opportunity for reasonably straightforward displacement of a significant amount of coal. This assessment, which draws upon another recent analysis, is presented first.

An analysis of the impact of a \$50/tonne cost of carbon on wind power was also conducted, and those results are discussed second. Wind was selected because cost projections for wind power indicate that this technology will be competitive with other electricity generation sources according to the electricity costs modeled in the HE/LC scenario of this study. In addition, wind power is already successfully penetrating electricity markets in the United States and abroad.

This analysis is followed by estimates of carbon emission reductions that would be likely to result from hydropower upgrades and landfill gas capture and use. These estimates are derived from DOE and EPA studies relevant to market projections for those two technologies, respectively (Rinehart et al., 1997; EPA, 1993).

Finally, other key renewable power technologies are discussed briefly. We present estimates of the likely contribution of these technologies in 2010, developed through comparisons and extrapolations from earlier projections (Office of Energy Efficiency and Renewable Energy, 1997).

#### **7.3.1.1 Cofiring Coal with Biomass**

Cofiring biomass with coal has the technical and economic potential to replace at least 8 GW of the nation's coal-based generating capacity by 2010, and as much as 26 GW by 2020. Though the current substitution rate is negligible, a rapid expansion is possible with the use of wood residues (urban wood, pallets, and secondary manufacturing products) and dedicated feedstock supply systems (DFSS) such as willow, poplar, and switchgrass.

The current coal-fired power-generating system represents a direct opportunity for carbon mitigation by substituting biomass-based renewable carbon for fossil carbon. Extensive demonstrations and trials have shown that biomass can replace up to about 15% of the total energy input with little more than burner and feed-intake system modifications to existing stations (CONEG, 1996). Since large-scale power boilers in today's 310-GW-capacity fleet range from 100 MW to 1.3 GW, the biomass potential in a single boiler ranges from 15-150 MW.

Preparation of biomass to an appropriate size of less than one-quarter inch, with a moisture content of less than 25%, can be achieved using existing commercial technologies. "Tuning" the combustion output of the boilers causes little loss in total efficiency, implying that the biomass-to-electricity combustion efficiency is close to the 33-37% range of an unmodified coal plant, an efficiency that stand-alone biomass generating capacity has yet to demonstrate.

#### **Economics**

The cost of implementing biomass cofiring varies from site to site. It is influenced by the space available for yarding and storing the biomass, the installation of size-reduction and drying facilities, and the nature of the boiler burner modifications required. The cost is expected to be in the range of \$100-\$700/kW of biomass capacity. Early trials indicate that a median value of about \$180/kW is likely. A 100-MW coal plant with 10% biomass substitution would then require an investment of \$1.8 million. There is an O&M cost increase of \$70,000/year over coal, as a result of the need for an additional yard worker to handle the biomass. Assuming a GENCO recovers its investment cost in three years, the annual fuel offset then has to be \$670,000 to cover

capital recovery (\$1.8 million) and increased O&M costs (\$210,000 for three years). If the average price of coal is about \$1.40/MBtu (million Btu), the annual fuel cost of coal is \$1.081 million (10 MW of biomass capacity at 85% capacity factor and 32.9% thermal efficiency, 10,337 Btu/kWh). The allowable cost of biomass then is \$411,000, or about \$9/tonne. Above this cost, the biomass would have to be subsidized to encourage a GENCO to use biomass cofiring.

### **Fuel Costs**

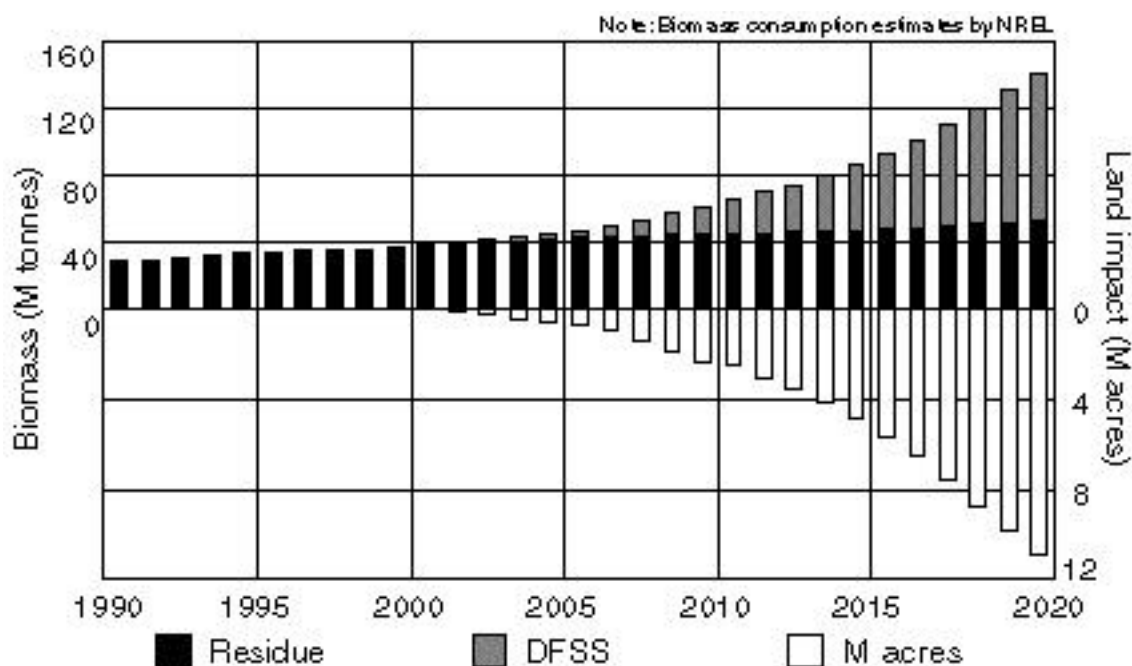
Near-term potential biomass feedstocks are those residues available within a radius of about 50 miles around a plant. Data from existing biomass power plants in the Northeast and California indicate that there are extensive sources of biomass residues available for about \$0.50/MBtu (less than \$9/tonne). Transportation costs limit the range over which such biomass feedstocks can be acquired and, in the long term, there are likely to be dedicated feedstock systems much closer to the power plants. By definition, residues (e.g., urban wood residues, rights-of-way clearance, construction and demolition wood, pallets, and sawdust shavings from secondary wood processing) are finite and will respond to the prices offered for them.

Dedicated feedstocks would not be bound by this constraint. However, such feedstocks are much more expensive than residues. With current technology the price is about \$2/MBtu, although the current development goal is in the range of \$1-\$1.50/MBtu. It is assumed that an estimated 10.4 million acres will be needed to reach a nominal production of 86 Mt by 2020. Because DFSS is in an early stage of development, the model assumes that the initial planting will yield only about 6 tonnes/acre by 2002 (today's state-of-the-art), and that by 2010 the yield will be closer to 8 tonnes/acre. Today's costs are high; \$45/tonne is feasible, but a combination of learning-curve improvements and economies of scale should bring the cost down to about \$32/tonne by 2010. The competing coal price is assumed to be \$1.40/MBtu (\$1.33/GJ) throughout.

### **Biomass Substitution Potential**

The cofiring estimates in this section were derived from a 30 GW scenario for all biomass technologies, developed by NREL for the current Biomass Power Program Strategic Plan. This scenario is for a mix of steam, cofiring, and integrated gasification/combined cycle (IGCC) biomass generation. However, the resource plan that was developed, which included residues and DFSS, is independent of the end use and involves the development of 11-12 million acres of land for DFSS by 2020, or just under 3 million acres by 2010. The resource development shown in Figure 7.11 is used as the basis for this carbon assessment. This indicates that DFSS would come on rapidly after the year 2001 and assumes that residues would be capable of only a small increase in quantity, since much is already being utilized. The average cost of residues is expected to increase gradually, while the cost of DFSS crops is expected to demonstrate a strong learning curve and large economies of scale.

Figure 7.11 30 GW Strategic Plan Scenario



### Timing

While a coal-fired station could be modified for cofiring in less than one year (including environmental permitting), a biomass resource assessment, contractual arrangements, and logistics for biomass residues could take the better part of 18 months, based on actual project experience. Although the availability of residues is assumed to be significant and would ultimately supply about 50 Mt, price and availability are likely to be variable. The price will no doubt increase with the level of demand; therefore, the biomass feedstock supply is expected to be a blend of DFSS and residues.

The DFSS component is predicated on making a start on land accumulation (whether purchases, leases, or cooperatives), with land preparation and planting in 1999. A significant effort will be required to initiate development of the 11-12 million acres proposed for 2020; today, discussions are about DFSS demonstrations at the 1000-acre level. Adequate clonal material and management systems for planting, tending, and harvesting will also need to be developed. The crops of choice in much of the Northeast and Southeast are probably woody species, which would require extensive nursery activity to put the needed clonal material in place for planting out. With willow, the first harvest cycle would be four years after planting and a rotation of three years thereafter. For poplar, the cycle is likely to be in the range of six to eight years.

### Environmental Issues

Because biomass generally contains significantly less sulfur than coal, cofiring with biomass could reduce SO<sub>x</sub> emissions. Early results suggest that there is also a NO<sub>x</sub> reduction potential using woody biomass. However, most coal-fired power stations have efficient precipitators and some have sulfur-capture technologies, so the net environmental effect of 10% biomass substitution (on an energy basis) appears to be negligible. The solid wastes (ash) would be little changed in either composition or mass (most biomass has considerably less ash than coal). But some stations sell fly ash to Portland cement manufacturers, so there may be a need to negotiate the acceptance of mixed biomass and coal ash in such applications with respect to ASTM standards.

The DFSS environmental impact is dependent on the choice of lands for plantations. Replacing annual cropland with perennial DFSS appears to result in a net environmental gain. Results for pasture land are probably negligible and replacement of forest may result in some increased impacts.

The use of residue has the potential to offset landfilling as well as potential methane emissions from landfilling clean biomass materials. Experiences in California indicate that the issue will be one of rationalizing the cost distribution between the waste generator, the hauling contractor, and the generating station receiving the residue rather than it going to a landfill. If such negotiations were successful, and the generating station could guarantee reception of the residues at all times (many urban wood residue generators do not have storage facilities), both residue costs and their availability could improve significantly.

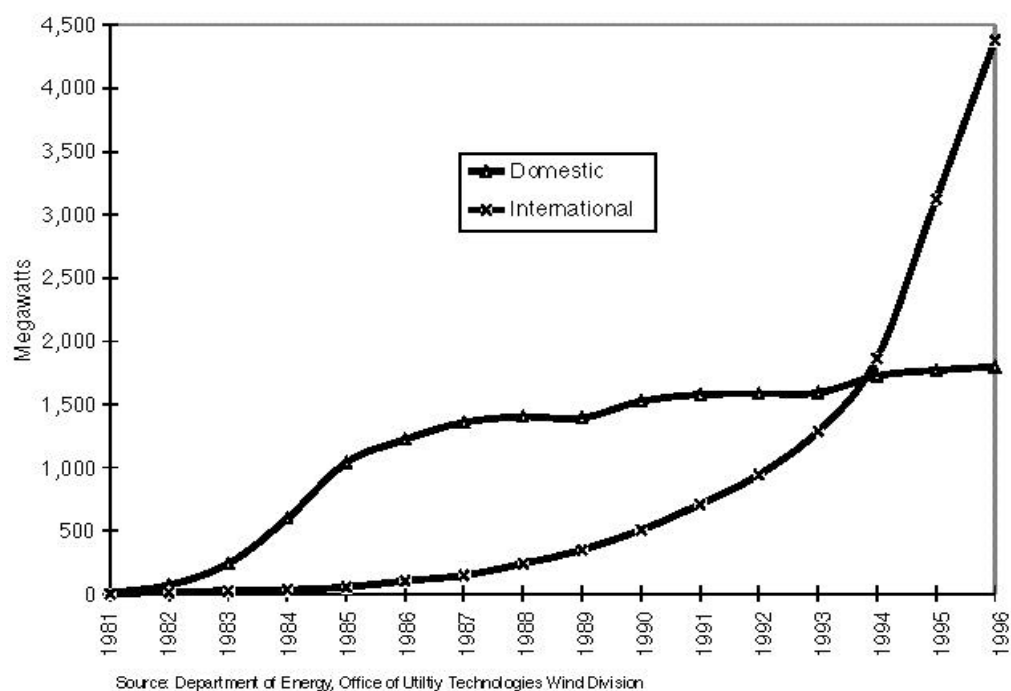
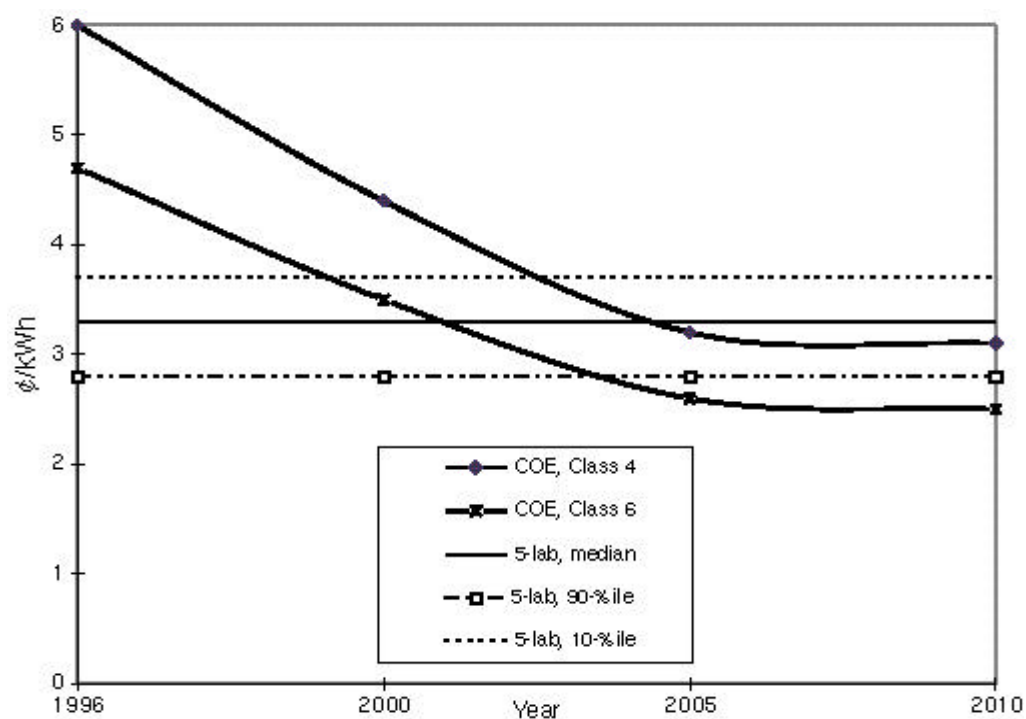
### **Impact on Carbon Emissions**

Given the technical and economic potential described above, it is probably reasonable to assume additional biomass-cofired capacity of 8-12 GW by 2010, which should reduce carbon emissions by 16-24 MtC.

#### **7.3.1.2 Wind Power**

The development of wind power systems has progressed quite rapidly since 1980. There are approximately 1800 MW of wind capacity operating in the United States today, and another 4300 MW of capacity overseas (Figure 7.12). This capacity growth is almost certain to continue because of continuing decreases in the cost of wind-generated electricity as well as growing interest in emission-free power derived from local, renewable resources. Figure 7.13 shows the projected cost of wind-generated electricity for wind farms located in Class 4 and Class 6 resource sites (as presented in DOE's 1997 Technology Characterizations). Class 4 sites have average wind speeds of 5.6-6.0 m/s, Class 6 sites have average wind speeds of 6.4-7.0 m/s, both measured at a height of 10 meters. Figure 7.13 also displays the median, 10th percentile, and 90th percentile of electricity generation prices in 2010 based on the HE/LC case described in Chapter 6. As these projections indicate, wind power prices are projected to drop below the median 2010 price for that scenario before 2005. Thus, strictly on a price-of-energy basis, in this scenario wind power will be able to compete favorably with other power sources for several years prior to 2010.

In addition to the price of energy, a number of other factors will affect the extent to which wind power systems will be adopted between now and 2010. These include, for example, the overall market for new power systems, the price penalty that wind power will encounter for providing intermittent power, and the price advantages that wind power will realize because it is a "green" power source and because it is not subject to the risk of future fuel price increases. Because the level of influence of each of these factors has not been analyzed, it is difficult to project their combined impact.

**Figure 7.12 Domestic and International Wind Power Capacity, Grid-Connected****Figure 7.13 Projections of Wind Power Costs**

In the AEO97 reference case forecast, EIA projects electricity generation to increase by about 800 TWh by 2010, from 3083 TWh in 1995 to 3874 TWh in 2010 (EIA, 1996). In this context, EIA projects a total of only 3800 MW of wind generating capacity. The Quality Metrics analysis by the Office of Energy Efficiency and Renewable Energy (EERE) of the impacts of its R&D program estimates that additional installed wind power generating capacity will reach 8 GW and contribute approximately 29 TWh to the electricity market by 2010 if wind program goals are met. This will result in a carbon emission reduction of 6 MtC. Neither of these projections, however, assumes a major new market policy to promote wind power.

In the HE/LC case of this study, electricity generation will increase by significantly less than in the business-as-usual case. Thus, the HE/LC scenario presents a much smaller target market for new power-generation sources. However, under the transition of the utility sector to a competitive market, it is very likely that newer technologies with lower generating costs will displace some existing generation capacity with higher generating costs. Moreover, in the HE/LC scenario, generation costs are projected to be more than 25% higher than in the base case. Thus, as illustrated in Figure 7.13, wind power generation costs will be highly competitive in this marketplace, so displacement of higher-cost existing generation by wind is likely. In an attempt to model the penetration of wind under these conditions, the ORCED model was run using the wind technology characteristics developed by the Office of Utility Technologies (Office of Utility Technologies, 1997). As might be expected, the results indicated that the level of wind penetration in this case is quite sensitive to the actual input parameters. According to the model, for example, using the cost and performance characteristics projected by DOE for the year 2005 could lead to the adoption of as much as 50,000 MW of wind power by 2010. Using 160 kg/MWh, the average carbon intensity of the generation displaced (see Chapter 6), this would result in a carbon emission reduction of 28 MtC. Because the ORCED model indicated that this new wind capacity would displace coal-fired generation, a higher conversion ratio (275 kg/MMh) is used to estimate carbon emission reductions, resulting in an estimated reduction of 48 MtC.

This level of penetration would require wind-turbine manufacturing capacity to expand at a rate of approximately 25% per year. As Figure 7.12 indicates, this level of wind capacity expansion has been reached in the past. Europe's experience with wind power also indicates that this technology can expand quite rapidly. It is possible for the manufacturing industry to respond quickly to market demands, since most of the components of wind systems (generators and gearboxes) are readily available, and not specific to wind technology. In 1991, the European Wind Energy Association set a goal of 4 GW of wind by 2000. This goal has been realized already in 1997, and the new targets are 8 GW by 2000 and 40 GW by 2010. Given that Europe is a much more land-constrained continent with generally lower wind resources than the United States, this comparison suggests that 50 GW of wind power capacity can be realized in the United States by 2010 in the context of a strong policy environment.

The HE/LC context of this analysis assumes a policy environment that acknowledges the need to address global warming. In such an environment, renewable energy, including wind power, will be able to demand somewhat higher prices because of consumers' preferences for green power. The value of that premium is not yet known.

It is well-documented that wind resources in the United States are quite extensive. For example, an assessment of wind resources and access to transmission indicates that more than 115 GW of Class 5 and Class 6 sites are within 5 miles of existing lines, and more than 1,000 GW Class 4 sites are within that same range (Parsons et al., 1995). This assessment excludes sites that are not suitable for wind farm development, such as cities and wilderness areas. Thus, 50 GW could probably be developed primarily in Class 5 and Class 6 areas, which means that they will operate with relatively high capacity factors and low costs of energy. (The Draft Technology Characterizations indicate that capacity factors will be 45% in Class 6 regions and 35% in Class 4 regions by 2005.)

This analysis does not take into account the fact that wind-generated electricity will probably face at least a partial price discounting because wind power is not fully predictable. At this time, the level of this discounting is simply not known. To date, with low levels of penetration into grid-connected generation, intermittency has not been an issue. There are some indications that the range of electricity prices in a competitive market will be fairly narrow. For example, prices for electricity transactions on the Continental Power Exchange during peak

hours generally vary only by about 2 cents/kWh (Continental Power Exchange, 1997). This implies that price variations between different generation sources cannot vary by more than that, and it is likely that the difference will be much smaller under full competition.

In summary, analyses indicate that total wind power capacity in 2010 could range from as low as 5 GW, based on a simple extrapolation of today's energy economy, to as high as 50 GW in an environment that includes competitive pricing and policies emphasizing control of carbon emissions. Given these results, it is probably reasonable to estimate that additional wind capacity will be 8-23 GW in 2010. This translates into electricity contributions of 28-81 TWh, resulting in reductions of carbon emissions of 6-20 MtC relative to the BAU forecast for 2010.

### 7.3.1.3 Increasing Generation and Capacity at Existing Hydropower Plants

Hydroelectric power currently supplies about 10% (78 GW) of the nation's electricity and constitutes 84% of the nation's generation from renewables (EIA, 1996). Hydroelectric power plants produce no greenhouse gas emissions during operation (DOE, 1994). In the 1940s, 40% of the country's electricity came from hydropower plants (Williams and Bateman, 1995). The adverse environmental affects of some hydropower projects are now relatively well known (e.g., Mattice, 1991), but significant progress is also being made in mitigating these problems (Sale et al., 1991).

Hydroelectric power uses the energy of falling water to generate electricity. Hydroelectric generation technologies for utility-scale applications are generally considered to be mature, with turbine efficiencies typically in the 75%-85% range (OTA, 1995). There are three types of hydropower facility:

1. Most hydropower plants use dams to raise the water level, which increases the water's potential energy, and allows for regulation of the water availability. Conventional hydropower (with reservoir storage) can provide baseload, intermediate, or peaking power, depending on the availability of water and project design (OTA, 1995).
2. Run-of-river systems do not use large dams or storage reservoirs. Instead, smaller diversion structures are used to channel some of the water through a canal or penstock to a powerhouse, after which the water is returned to the river. Run-of-river systems avoid some of the costs and environmental impacts associated with large hydro facilities.
3. Pumped storage projects use off-peak electricity (usually from a baseload power plant) to pump water to an upper reservoir; this water is later released to flow through a generator during periods of peak demand. Such plants are net consumers of energy. Although pumped storage is not a renewable energy technology, it can result in a net reduction in greenhouse gas emissions when the fuel providing electricity for pumping has a lower carbon content than the fuel being displaced by the pumped storage generation (DOE, 1994).

The main challenge for hydropower in recent years has been the growing concern over its local environmental impact. By damming rivers to create storage reservoirs, hydro facilities can have an adverse effect on terrestrial and aquatic ecosystems. Wildlife habitats can become inundated. Fish migration routes can be cut off, and fish can die in the generating turbines or because the downstream water quality and habitat are changed. Plants that grow along the riverbanks can be disrupted by changes in the natural water level, both above and below the dam, and large or rapid variations in the amount of water being discharged can disrupt aquatic habitats and accelerate erosion downstream.

Regulatory measures — such as the licensing of non-federal hydropower projects and the Endangered Species Act — are reducing the environmental impact of hydropower projects, but they are also reducing total electricity production from this energy source. Between 1995 and 2010, 19 GW of hydropower at non-federal projects will be subject to relicensing. Recent trends indicate that relicensing results in an average 8% loss in generation due to the imposition of new environmental constraints on operation.

Under the HE/LC scenario, and assuming a sustained regulatory reinvention effort between now and the year 2010, incentives could be in place to increase hydroelectric power generation in either of two ways. Neither of these opportunities involves the construction of hydropower plants at new sites. However, both will require continued R&D to improve the design of turbine systems and to minimize adverse environmental effects:

Increasing generation at existing hydropower plants. This option consists of modernizing and upgrading existing turbines and generators to increase their efficiency and/or electrical output. With enabling incentives, upgrading hydropower plants can result in energy production gains of 5%-10%. Hydropower upgrades would also have significant environmental benefits, because new generating technologies offer improved fish passage, better water quality, and new opportunities for improving downstream aquatic habitats.

Adding generating capacity at existing dams. A recent resource assessment identified 20 GW of undeveloped hydropower capacity at existing dams (Rinehart et al., 1997). About 36,000 GWh of new hydropower generation could be added by developing these sites between 1995 and 2010 (Office of Conservation and Renewable Energy, 1990).

Further expansion of hydropower capacity is possible, but unlikely until after 2010. The national hydropower resource assessment (Rinehart et al., 1997) has identified an additional 11 GW of environmentally acceptable hydropower at undeveloped sites (those requiring the construction of new dams or diversions). These resources may eventually be developed, given more advantageous economics, regulatory reinvention, and/or technology improvements. Further development of efficient low-head generating technologies would encourage deployment at the many low-head sites that are currently unsuitable for hydropower additions.

Considering only the near-term options, and the fact that there may be some loss of hydropower capacity due to relicensing issues and environmental mitigation regulations, net capacity additions by 2010 could be 10-16 GW, reducing emissions by 3-5 MtC. Additional carbon savings can be achieved after 2010 with continuing advancements in generating technologies and environmental mitigation techniques.

#### **7.3.1.4 Landfill Gas**

When food scraps and other organic wastes in landfills decompose, they produce methane. Methane is a potent greenhouse gas that is also the main ingredient of natural gas. According to the Intergovernmental Panel on Climate Change, each kilogram of methane is about 21 times more effective at trapping radiation in the atmosphere than a kilogram of carbon dioxide. Landfills are the largest source of anthropogenic methane emissions in the United States; they are responsible for almost 40% of these emissions each year (EPA, 1997).

New EPA regulations require operators to seal larger, closed landfills with a special cap, collect the gas, and burn it to prevent atmospheric releases of methane. But wells sunk into landfills can capture the gas before it escapes the surface. It can then be used for a variety of applications, including generating electricity.

Today, about 165 landfills recover and utilize methane as a fuel. Various estimates (Governmental Advisory Associates, 1994; EPA, 1997) indicate that between 300 and 750 of the country's 3500 landfills could economically recover methane using currently available technologies. The development of more efficient, less expensive technologies for gas recovery, clean-up, and utilization could accelerate the adoption of landfill gas-to-energy systems. For example, highly efficient, experimental fuel cells have operated on landfill gas processed using new clean-up technology.

By 2010, 0.2-0.5 quads of energy per year could be recovered from the methane in landfills and converted to electricity. Taking into account the difference in the radiative effects of methane and CO<sub>2</sub>, this represents the equivalent of 25-53 MtC in reduced emissions (DOE, 1994).

### 7.3.1.5 Other Renewable Power Technologies

This section examines three more renewable electric technologies: photovoltaics (PV), geothermal power, and solar thermal power. Figure 7.10 illustrates that the costs for these three technologies have also decreased sharply over the past 15 years. It is very likely that this trend will continue. While none of these technologies are expected to contribute as much electricity as biomass cofiring or wind power by 2010, their role in 2010 electricity markets may be significant and growing.

#### Photovoltaics

Photovoltaics (PV) uses solar cells to generate electricity from sunlight without any emissions or moving parts. This technology has made substantial progress since its first successful application in space. While PV power costs are still significantly higher than the costs of other renewable technologies, sales of PV power systems have been growing steadily, probably because of the many unique advantages of PV. These include modularity (applications can range from solar calculators to power stations), widespread applicability (since adequate solar resources are widely available), and ease of integration into the built environment (through incorporation into building facades, roofing materials, highway sound barriers, parking-lot structures, etc.). The most important application of PV today is in stand-alone systems that provide power to remote water pumps or off-grid residences, for example. Because approximately two billion people live in villages without grid electricity, remote power represents a very large and important market for PV in developing countries.

For grid-connected applications, one of the most promising trends in the past few years is “building-integrated” PV. Numerous buildings have been constructed — primarily in Europe, Japan, and the United States — that incorporate PV panels in windows, awnings, or roofing materials. Thus, the PV panels serve a dual function, which effectively lowers the cost of their role as power generators. In these applications, the PV power directly displaces grid electricity at the end point of the delivery system, where it has the greatest value. Another advantage of PV is that its peak power output generally coincides with peak electricity demand, which further enhances its market value.

Worldwide sales of PV power systems have grown to nearly 100 MW per year, up from 10 MW in 1982, an average annual growth rate of about 20%. This rate of growth is likely to increase as a result of numerous programs promoting PV for village power in developing countries as well as programs promoting greater use of PV in several developed nations. One example is the U.S. Million Solar Roofs program, announced by President Clinton at the United Nations on June 26, 1997. Others include Japan’s Sunshine Project, Germany’s subsidy of up to 70% of PV system costs, and Switzerland’s PV Schools Program.

EIA estimates that total installed PV capacity in the United States will be only 0-2 GW in 2010 (EIA, 1996). However, an independent assessment of the impact of DOE’s R&D programs indicates that, by 2010, installed U.S. PV capacity will be approximately 1.3 GW under a BAU scenario (Office of Energy Efficiency and Renewable Energy, 1997). Using this as a starting point, and considering the many advantages of PV, an estimate of installed capacity of 4-7 GW in 2010 is probably reasonable for the HE/LC scenario. This would provide 6-13 TWh of electricity and reduce carbon emissions by 1-2 MtC. One important addition to PV capacity will come from the recently announced Million Roofs Initiative, which will result in 1-2 GW of new capacity.

The market trends for PV in 2010 are probably more significant than its energy and carbon contributions. By 2010, PV energy prices will be substantially lower than they are today, and we will have had considerably more experience with the development and use of building-integrated PV products. In this context, the United States will be moving into a situation in which a significant and increasing fraction of construction includes PV generation capabilities.

### Geothermal Electricity

Geothermal power technologies use the thermal energy from underground reservoirs of hot water or steam to produce electricity. With higher temperature resources, the steam is used to drive a turbine directly; with lower temperature resources, a binary technology is used in which the hot water vaporizes another working fluid, which then drives a turbine. These geothermal power-generation technologies are considered fairly mature. The major challenge lies in locating and characterizing the size and longevity of specific geothermal reservoirs.

Approximately 3 GW of geothermal capacity is installed in the United States today. While EIA estimates that geothermal capacity will increase by only 0.2 GW by 2010 (EIA, 1996), DOE's recent Quality Metrics Study indicates that geothermal power capacity will increase by 5.8 GW, and electricity production will increase about 45 TWh, in a BAU scenario (Office of Energy Efficiency and Renewable Energy, 1997). While a \$50/tonne cost of carbon would improve the economics for geothermal, it is not expected to provide as much of a boost as it does for wind or biomass. It is probably reasonable to use the DOE estimate as the lower boundary, and project that total installed geothermal power capacity in 2010 under the HE/LC case will be 8-16 GW. The 6-14 GW increase in geothermal capacity over today's level would reduce carbon emissions by 6-16 MtC.

### Solar Thermal Electric Technology

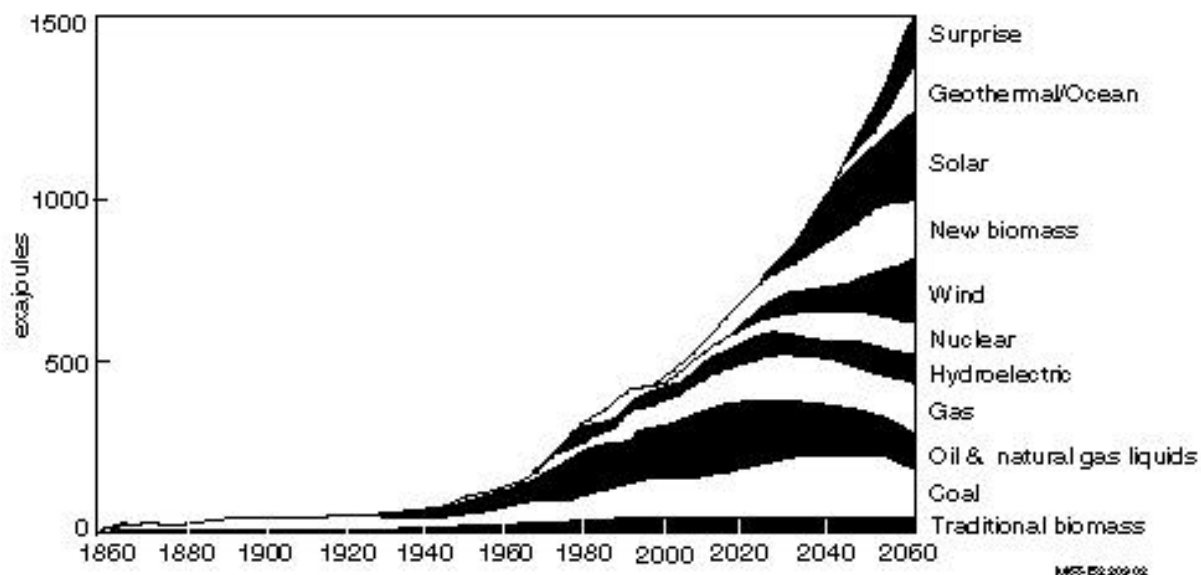
Solar thermal power technologies use mirrors to concentrate direct sunlight onto a thermal receiver, thus creating a high-temperature energy source that can be used with a heat engine to generate electricity. There are three types of solar thermal power systems: parabolic troughs, power towers, and dish/engine systems. Parabolic trough systems use large fields of linear parabolic reflectors, each of which heats a fluid flowing through a receiver pipe located along the focal line of the reflector. About 350 MW of these systems are operating in California. A 10-MW demonstration of a solar thermal power-tower system, which uses large mirrors to direct solar rays to a thermal receiver atop a tower, is also operating in California. The third technology uses individual parabolic dish reflectors to provide thermal energy to a Stirling engine mounted at the focal point of the dish. A few individual prototype units, which have power outputs of about 10-25 kW each, are being tested in the United States.

While EIA projects negligible gains for solar thermal generating capacity by 2010 (EIA, 1996), DOE's recent Quality Metrics Study suggests that solar thermal systems will provide approximately 2 TWh of electricity in 2010 in a BAU scenario (Office of Energy Efficiency and Renewable Energy, 1997). Under the HE/LC scenario of this study, an estimate of 0-2 GW capacity and 0-6 TWh electricity generation in 2010 is probably reasonable. This would reduce carbon emissions about 0-1 MtC.

## 7.3.2 The Long-Term Role of Renewables

As indicated at the beginning of this section, it is quite likely that renewable energy technologies will play a crucial role in limiting carbon emissions and global warming in the long term. Continued domestic and international economic development that does not foster further global warming will require greater energy consumption coupled with lower carbon emissions. The only options are thus low-carbon energy supplies, such as nuclear power or renewables, or the sequestration of carbon emissions from the use of fossil fuels. With the continuing technological development and cost reductions of renewables, renewables may become preferred energy resources some time within the next one to three decades. Moreover, they will probably expand to become the world's primary energy resource in the latter half of the next century. In fact, just such a transition was suggested recently by Shell International (Figure 7.14) (Royal Dutch/Shell Group of Companies, 1996).

**Figure 7.14 Sustained Growth Scenario from Shell International (Reproduced courtesy of Shell International Petroleum Company)**



This subsection describes the future direction and likely accomplishments of continuing R&D in renewables. This discussion should lend credence to the prediction that non-hydro renewables will make the transition from a minor to a major contributor to the world's electricity supplies.

### Biomass Power

The most important R&D areas for biomass power are in gasification/conversion systems and in feedstock production. Gasification involves converting the solid biomass feedstock material to a gas that is cleaned and then burned in a combustion turbine or used in a combined-cycle plant. This technology is currently in the initial demonstration stage of development.

The importance of this technology is that it can take advantage of advanced turbine designs and heat-recovery steam generators to achieve almost twice the efficiency of currently installed biomass technologies (NREL estimates, 1997). High-pressure gasification technologies yield the highest efficiencies, but they also require the development of efficient, cost-effective methods for cleaning the hot gases before they enter the turbine.

On the biomass production side, genetic research is likely to produce energy crop species that provide consistently higher biomass yields on an energy-content basis, thus providing a proportional reduction in biomass feedstock costs. Related research into new species designed for better fuel production also looks promising in terms of significantly decreasing biofuels costs over time. Research into advanced agricultural methods will also lower feedstock production costs over time. Finally, the development of simpler feedstock handling and processing methods will also lead to lower costs. Whole-tree processing methods, for example, which avoid the cost of chipping the wood before processing or use, could reduce the cost of harvesting and delivering the biomass to the power plant by about one-third (OTA, 1995).

Taken together, improvements in biomass power conversion as well as feedstock production and processing could reduce the cost of electricity from biomass to about 3-4 cents/kWh. This would make biomass power very economical in comparison to other mainstream electricity sources. As biomass power expands, most of it will employ dedicated feedstocks. In this context, biomass use will entail low net carbon emissions. These net

emissions primarily result from the combustion of fossil fuels in production and delivery, because the carbon emitted during conversion will be reabsorbed as new feedstock grows. Thus, biomass power can become a major contributor to reducing overall carbon emissions from electricity generation in the coming decades.

## Wind Power

The technological and economic feasibility of wind power — both in the United States and abroad — has already been well established, as the wind generation capacity curves in Figure 7.12 indicate. Nonetheless, major advances for wind power technology in both the short-term and long-term are likely. These are predicted for the short-term by DOE's cost and performance projections (Office of Utility Technologies, 1997), as illustrated in Figure 7.13.

Wind turbine design is the most critical R&D area. In general terms, the research goals are to produce turbine designs that have half of the material content of today's turbines, at perhaps three-quarters of the material cost (to account for more expensive materials), but with higher efficiencies and longer lifetimes. Such design improvements will not only lower the cost of wind-generated electricity, they will also make it economically practical to utilize the widespread, somewhat lower quality wind resources found in Class 4 wind regimes. Some of the critical research needed to achieve these goals includes continued empirical research into the air-turbine blade interface, computational fluid dynamics modeling of that interaction, and fatigue testing and structural modeling coupled with materials research. This is all aimed at producing more efficient turbine blades that minimize material utilization while extending blade operating lifetimes.

Another important area of R&D concerns the development of direct-drive generators and improved power electronics. This will yield higher conversion efficiencies and more durable power-conversion components, eliminating the need for a gearbox in the drive train. A major challenge will be the integration of advanced components and controls into large-scale, utility-class hardware.

There is also considerable room for improvement in turbine manufacturing processes through process development and automation, since today's turbine blades are still largely built by hand.

A fourth critical research area is that of wind prospecting and prediction. Wind regimes are extremely site-specific, so even though wind resources have been broadly categorized for the nation and the world as a whole, the siting of individual wind farms requires detailed information in order to select the best site. Wind speeds can vary dramatically over the course of seconds (due to turbulence), hours (diurnal variations), days (weather fronts), and months (seasonal variations). The best locations are those with strong, sustained winds having little turbulence. Finding such locations requires extensive prospecting and monitoring (OTA, 1995). The development of better tools for resource characterization and prediction will both improve the economics of wind power and enhance its value by enabling utilities to more reliably predict the power output from specific wind power plants.

Another important thrust for research is to address siting issues. For example, the tops of ridges are often good wind sites, but such a visible location for a wind farm can be a cause for concern when the site is either close to a population center or in an area of particularly great scenic value. To date, there have been virtually no studies to understand the local values associated with the visual impact of wind systems relative to other energy technologies in the United States. Yet such analysis could play a key role in decisions about the adoption of wind power in specific regions. Another environmental consideration affecting site selection is the potential risk to birds, particularly raptors, which sometimes fly into the rapidly turning rotor blades. This, too, seems like an issue that may well be resolved through research to understand the scope of the problem relative to other threats to bird species as well as the development of ways to keep birds a safe distance from moving turbine blades.

In summary, the research front for wind power technology is very broad. Achievements are likely to lead to widespread adoption and application of this electric power technology throughout the world, wherever resources are adequate, over the next few decades.

### **Geothermal Electricity**

Both current geothermal power systems and advanced geothermal power technology concepts will benefit from continuing R&D.

Today's geothermal power plants use the thermal energy from hot water and steam in hydrothermal reservoirs to generate electricity. While the power conversion and drilling technologies related to these power plants are considered relatively mature, they will also benefit from R&D in heat exchangers, hot fluid management systems, and new thermal conversion cycles. These activities alone could result in energy cost reductions of at least 20% in the next few years (NREL estimates, 1997).

The most important R&D area for conventional geothermal technology is resource exploration and characterization. The cost of geothermal electricity is highly dependent on resource characteristics such as temperature, depth, sustainable extraction rate, fluid chemistry, and ease of drilling. By 2020, improvements in drilling technology, advanced seismic data gathering, and better computer modeling and interpretation of the data could lower the average cost of locating and assessing geothermal resources by 50% (NREL estimates, 1997).

In the long term, geothermal power plants could make use of hot dry rock resources — areas of exceptionally hot rock (above 150°C) that have little or no water in them. Energy can be extracted from these zones by injecting water from the surface underground, where it is heated. Although the engineering feasibility of extracting energy from hot dry rock has already been demonstrated (Secretary of Energy Advisory Board, 1995), further R&D is necessary to make the technology commercially viable. With success in that endeavor, the potential for geothermal power would be vastly expanded because hot dry rock resources are widely available.

### **Photovoltaic Power Systems**

Although PV power technology has already experienced major gains in both performance and economics as a result of R&D conducted over the past 30-40 years, there is still considerable potential for further improvements. This is true for essentially all aspects of PV power systems, including research on basic photovoltaic materials, development of high-efficiency PV cells and modules, development of better PV power products, lower cost manufacturing processes, and improvements in the various components of PV systems.

A good example of the potential of PV R&D is found by comparing the module efficiencies of current commercial PV modules with the efficiencies of individual solar cells. For crystalline silicon PV technology, the technology representing about 90% of current sales, commercial module efficiencies are generally between 10% and 15%, while the best laboratory cell efficiencies are well above 20%. For thin-film PV technology, which includes amorphous silicon, copper indium diselenide, and cadmium telluride modules, current module efficiencies are generally well under 10%, but cell efficiencies are above 15%. Thus, in all cases, progress in commercial products would be virtually assured through the replication of established laboratory results. There is also clearly the potential for greater increases in cell efficiencies over today's laboratory results. Some of the research tools that are being applied include computer modeling of various semiconductor materials and atomic-level engineering of new devices to better understand their photovoltaic and electronic properties.

Looking ahead, we find that significantly greater efficiencies are possible. For example, multi-junction cells have been tested with efficiencies above 30%. At this time, these are small, laboratory-scale devices whose initial application is expected to be with concentrators, in which the cost of the cell is significantly offset by the increased solar energy captured by the optical concentrator. However, in a decade or two, it is certainly

conceivable that low-cost processes for making similar high-efficiency multi-junction devices will have been developed, which will make it possible to use them in conventional, flat-plate PV modules.

In the area of manufacturing processes, considerable effort is being made to perfect processes that provide uniform, high-quality materials for the thin-film technologies. The fruits of these efforts are likely to be realized in the next few years as a number of firms construct fairly large (5-20 MW per year) manufacturing plants based on the results of process research and development.

There is still considerable progress to be made in the development of PV power products. For example, many PV power systems today are still being individually designed for specific applications. Off-the-shelf PV power systems and consumer products (such as PV walk-lights, lanterns, and battery chargers) are becoming more available, but the commercial PV industry is still a long way from making it as easy to purchase a residential PV system as it is to buy a refrigerator. The development of products that are readily applied to such individual needs will have an important effect on PV electricity costs because it will increase the volume of sales. A particularly important set of PV products is likely to be PV components for building shells. These include windows, wall materials, awnings, and roofing materials that incorporate PV and are as readily installed as the components they replace in today's building industry. A reasonable long-term target is to have a large fraction of new construction incorporate such building-integrated PV products.

Finally, we will continue to see improvements in the balance-of-system components of PV systems. Examples include power conditioners and controllers, which serve as the electrical operating and interface system for integrating PV power modules with the load and/or the power grid. These components will continue to improve as well as benefit from developments in power electronics. Greater system integration is also likely, simplifying overall system design. A good example is the development of PV modules that incorporate dc-to-ac inverters, an activity that is currently under way.

In summary, PV technology will benefit from major R&D advances for many years to come, and these advances will significantly improve the economics of PV power. Among the implications of these advances, it is likely that PV power systems will reach prices of \$3000/kW by 2010, which is less than half the current average price. Further price reductions will no doubt occur beyond that.

### **Solar Thermal Electricity**

Solar thermal technologies will benefit from R&D in a broad range of areas. For example, successful development of durable silver/polymer reflectors will reduce reflector costs by 25% to 50% for all three technologies, reducing system costs by 10% to 20%. Improved reflectors and receivers will also allow higher operating temperatures and thus higher solar-to-electric conversion efficiencies. Technology advances for Stirling engines will directly benefit dish/engine systems; one of the most important areas is the extension of operating lifetimes between overhauls. The development and application of hybrid solar/natural gas systems will be particularly important for power tower and parabolic trough technologies. These will make it possible to provide dispatchable power and to use combined-cycle technology, as well as smaller solar fields without being penalized by smaller steam turbines, which tend to be less efficient.

By 2020, we are likely to see power-tower conversion efficiencies around 30%, compared with about 15% today, and dish/engine conversion efficiencies of about 35%, up from about 25% in current prototypes. At the same time, these technologies will cost less and be more durable. At this stage, they are likely to be fully competitive with other mainstream power technologies in areas with good solar resources throughout the United States and the rest of the world.

## 7.4 EFFICIENCY IMPROVEMENTS IN GENERATION AND TRANSMISSION & DISTRIBUTION

Lowering the heat rates of fossil-fueled generation results in greater efficiency (i.e., less fuel burned per electricity generated) and lower carbon emissions. OTA (1991, p. 320), for instance, suggests that improved maintenance could reduce heat rates by 5%, resulting in a reduction of 22 million tonnes of carbon emissions by the year 2000. OTA includes this measure in their “moderate” scenario, viewing it as either a low-cost or a no-cost measure. The rate of improvement assumed by OTA is consistent with a power plant performance monitoring and improvement project conducted by the Electric Power Research Institute (1986; 1989). Hirst and Baxter (1997) also note the value of cutting heat rates for fossil-fuel power plants, as a carbon reduction option. No efficiency improvements to existing fossil plants are assumed in the 1997 *Annual Energy Outlook*’s reference case (Schouberlein, 1997).

The Southern Company has had extensive experience with improving the efficiency of their electric utility system. Over a thirteen-year period, the Southern Company was able to reduce its heat rate by 5.8%, lowering it from approximately 10,300 Btu/kWh (in 1982) to less than 9,700 Btu/kWh (in 1994) (Southern Company, 1993; Siegel, 1997). This represents an improvement in fossil system efficiency from approximately 33.2% (in 1982) to 34.8% (in 1994). The current level of efficiency in U.S. fossil-fired power plants is approximately 33%. In addition to improving the company’s system-wide heat rate, the Southern Company was able to increase its reliability from 88% (in 1982) to 96% (in 1994) (Southern Electric International, 1996), and was able to increase its availability to approximately 86%. The current availability of U.S. fossil-fired power plants is approximately 81%.

These heat rate and availability improvements to the Southern Company’s electric system have provided benefits valued at \$1.1 billion/year. One of the largest benefits to the Southern Company has been from the deferral of 6,000 MW of new capacity. The cost of these heat rate and reliability improvements to the Southern Company is estimated at approximately \$325 million/year. The operation and maintenance activities that comprise these costs include: establishing a heat rate improvement training program, creation of a plant heat rate review board and a system heat rate technical network, assignment of an efficiency engineer at each plant, instituting a program of heat rate monitoring, and investing in design upgrades (Siegel, 1997).

The Southern Company’s experience is consistent with the OTA and EPRI estimate that a 5% heat rate improvement is technically feasible at a low cost or at no cost. Such an improvement would result in a concomitant reduction of 5% in the carbon emissions of the utility sector. Based on Chapter 6’s HE/LC case (Table 6.4), the electricity sector’s carbon emissions in 2010 would be 492 MtC. Although coal generation accounts for only 46.2% of the electricity generation forecasted for 2010, coal plants account for 81% (or 400 MtC) of the carbon produced by the electricity sector. A 5% reduction would represent 20 Mt of carbon emissions. Assuming that 35-65% of this total is feasible, a realistic estimate of the potential reduction is 7-13 MtC.

Improving the efficiency of transmission and distribution (T&D) systems is another supply-side option available to utilities. As with generation, T&D improvements can include both capital investments (for example, new transformers and conductors) and improved operations. Because T&D losses account for only about 7% of total generation, the opportunities to reduce CO<sub>2</sub> emissions through such mechanisms are limited. However, they could nonetheless be cost-effective. Improving T&D efficiency by 10% would cut emissions by almost 1% (Hirst and Baxter, 1997).

## 7.5 NUCLEAR PLANT LIFE EXTENSION

In both the AEO97 reference case and the restructured case described in Chapter 6, nuclear plants are projected to lose market share in the national mix of electricity generation. Similar trends are forecast worldwide, with the forecasted decline in nuclear power in Europe being particularly large (South, et al., 1997).

In the U.S., the nuclear power capacity of 99.2 gigawatts that existed in 1995 is projected to drop to 88.9 gigawatts in both the AEO97 reference case and the restructured case in 2010. This drop is primarily the result of the retirement of 17 plants whose licenses expire between 1999 and 2010. The combined capacity of these 17 plants is 11.5 gigawatts. The average capacity factor of the remaining plants ranges from 76-79% throughout the forecast, deviating little from the current capacity factor of 77%.

No additional nuclear units are actively under construction in the U.S. Therefore, no new planned units are assumed to come into service during the 2010 forecast. One nuclear unit, Watts Bar 1 owned by the Tennessee Valley Authority, received its license in 1996, but a few plants have also recently closed.

Nuclear power is a carbon-free source of electricity. Retaining as much as possible of its current power generation would therefore be an important carbon mitigation strategy in an economy where carbon emissions bear a charge of \$50 per tonne, as in the HE/LC scenario.

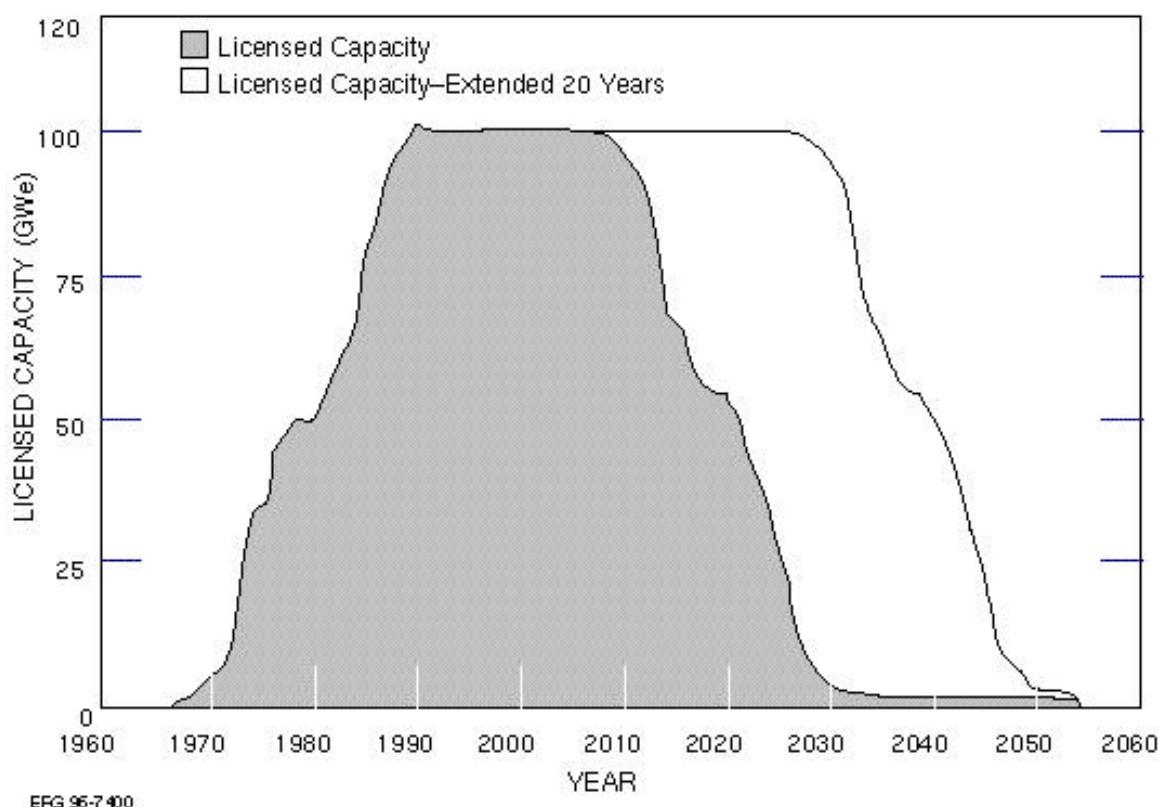
AEO97 defines a “high nuclear case” which assumes that every nuclear plant operating in 1996 has an additional 10 years of operation, as long as their operating costs do not exceed 4 cents/kWh. This 2010 forecast results in the closure of only three nuclear plants (totaling 1.3 gigawatts of capacity) due to license expirations and the addition of 10.2 gigawatts of new capacity from 14 plant lifetime extensions (EIA, 1996; Nuclear Regulatory Commission, 1996). Thus, nuclear capacity in EIA’s forecast for 2010 grows from 88.9 gigawatts (in the reference case) to 99.1 gigawatts (in the “high nuclear case”). Based on a capacity factor of 77%, this 10.2 gigawatts of capacity expansion from nuclear plant life extensions results in 69,000 GWh of additional nuclear energy in 2010, compared to the reference case.

According to EIA’s “high nuclear case,” 12 Mt of carbon would be offset by this additional carbon-free source of electricity. Using the capacity on the margin in the HE/LC case (with carbon emissions averaging 160 tonnes/GWh), we estimate that the carbon reductions from this additional nuclear resource drop to 11 MtC. A range of 4-7 MtC (from 35-65% of this potential) would appear to be a more realistic forecast for the HE/LC scenario. This range recognizes that it will not be economical or politically feasible to extend the operation of nuclear power plants with licenses that expire by the year 2010.

The AEO97 reference case forecasts that nuclear capacity in the U.S. will decline at an increasing pace after 2010, decreasing from 88.9 gigawatts in 2010 to 62.7 gigawatts in 2015. Thus, with the demand for energy continuing to grow, the impact of nuclear power as a carbon offset declines precipitously over this slightly longer planning horizon. Under the “high nuclear case,” the assumed 10-year nuclear plant licensing extensions (subject to the 4 cents/kWh maximum cost) increases nuclear capacity in 2015 from 62.7 gigawatts (in the reference case) to 94.7 gigawatts (in the “high nuclear case”). Thus, the magnitude of carbon offsets offered by this strategy becomes quite significant after 2010.

Figure 7.15 illustrates the accelerated role that nuclear power life extension could have in offsetting carbon emissions after 2010. Only 45 of the nation’s 105 nuclear plants have licenses that extend beyond 2020 (Nuclear Regulatory Commission, 1996). An effort to maintain the viability of this capacity could result in a very large contribution to carbon reductions over the next quarter century.

AEO97 does not estimate the cost of its “high nuclear case,” although it acknowledges that the physical degradation of some units would have to be reversed. OTA (1991) also notes the potential carbon savings of extending the useful life of all nuclear plants to 45 years, but assumes that this option involves either low costs or saves money. Understanding the effects of aging in order to better manage the aging nuclear infrastructure is an important R&D topic. Pressure vessel embrittlement and the degradation of cables, pumps, and valves can be better managed by advances in materials science and by developing and implementing advanced monitoring technologies. Such technologies are the result of R&D and help maintain the current licensing basis of the nation’s nuclear power plants, thereby enabling their operation to extend beyond the initial 40-year licensing period.

**Figure 7.15 U.S. Commercial Nuclear Power Reactor Generating Capacity**

## 7.6 ADVANCED COAL TECHNOLOGIES

To test the possible effects on carbon emissions of other advanced fossil-fired electricity generation technologies, we replaced the advanced technologies used by EIA with estimates from DOE's Office of Fossil Energy (see Table 7.6). These estimates changed the construction costs and heat rates for advanced combustion turbines, combined-cycle units, and coal units. ORCED did not select the advanced coal unit with either the EIA or the Fossil Energy estimates of this unit's costs and operating characteristics; in both cases, its initial cost was too high to warrant inclusion in the generation mix. The only significant change to occur was the replacement of the most advanced combustion turbine as specified by EIA with an older combined cycle unit. The net effect of this change on carbon emissions was negligible.

This limited analysis suggests that between now and the year 2010, highly efficient (i.e., a heat rate of about 7000 Btu/kWh) but expensive (i.e., a cost of over \$1000/kWh) advanced coal units cannot compete economically with either the generation mix that remains from the 1990s or with gas-fired combined-cycle units.

**Table 7.6 Base Case Technologies Compared to Advanced Technologies (costs in 1995\$)**

	Original	Alternative	Original	Alternative
<u>Advanced Gas Combined Cycle</u>				
Year of construction	2005	2005	2009	2010
Capital Cost, \$/kW	410	525	410	500
Heat Rate	6284	5688	5817	5538
Fixed O&M, \$/kW-yr	27	16	27	16
Variable O&M, ¢/kWh	0.05	0.015	0.05	0.015
<u>Advanced Gas Combustion Turbine</u>				
Year of construction	2002	2005	2008	2010
Capital Cost, \$/kW	339	400	374	364
Heat Rate	10873	8699	7793	8533
Fixed O&M, \$/kW-yr	11.9	17.6	16.9	17.6
Variable O&M, ¢/kWh	0.010	0.012	0.05	0.012
<u>Advanced Coal</u>				
Year of construction	2006	2005		
Capital Cost, \$/kW	1340	1050		
Heat Rate	9600	7064		
Fixed O&M, \$/kW-yr	34	26		
Variable O&M, ¢/kWh	0.25	0.2		

## 7.7 SUMMARY

Table 7.7 summarizes the potential reductions in carbon emissions that could occur as the result of the technology options discussed in this chapter. Each option is intended to reflect roughly the amount that could be achieved under aggressive policies combined with a carbon incentive of approximately \$50/tonne. The total carbon reductions from the options shown in Table 7.7 range from 80 to 117 MtC by the year 2010. Additional carbon reductions may result from landfill gas recovery, photovoltaics, geothermal, and solar thermal resources.

The analysis of renewable energy potential over the next quarter century indicates that with a vigorous and sustained program of research, development, and deployment, renewable energy technologies could be providing a greater and rapidly growing contribution to electricity generation by the year 2020. The potential contributions of carbon sequestration, advanced coal technology, and nuclear power were not explored in this report.

**Table 7.7 Carbon Reduction Potential of Selected Electricity Supply Technology Options in the HE/LC Scenario with Carbon Permit Price of \$50/tonne**

	<b>High-Efficiency/Low-Carbon Case (MtC)</b>
Converting coal-based power plants to natural gas	44
Cofiring coal with biomass	16-24
Wind	6-20
Hydropower	3-9
Efficiency Improvements	7-13
Extending the life of existing nuclear plants	4-7
<b>Total</b>	<b>80-117</b>

## 7.8 REFERENCES

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**ENDNOTES**

<sup>1</sup> Other approaches include (1) repowering with an advanced coal technology (integrated coal gasification combined cycle (IGCC), or pressurized fluidized bed combustion (PFBC)) or (2) plant performance (efficiency) improvements through various management and technical adjustments. With both of these “other” repowering options, the carbon emissions reduction potential is not as great as with NGCC due to (1) the magnitude of efficiency improvement and (2) the carbon (together with sulfur and nitrogen) content of coal versus natural gas.

<sup>2</sup> All coal-fired power plants greater than 50 MW, and projected to remain in operation, were considered for NGCC repowering: 22.5 gigawatts (GW) of capacity identified by EIA in AEO97 to be uneconomic were deleted, as were 47.5 GW determined to be unneeded due to end-use energy efficiency improvements (see Section 6). Appendix G-2 discusses the deletion of this capacity from the coal/gas repowering analysis.

<sup>3</sup> One million Btu (MBtu) is the equivalent of one thousand cubic feet (MCF) of natural gas. One trillion cubic feet of natural gas is abbreviated as TCF.

<sup>4</sup> This estimate of gas transmission cost may be high, since it may overestimate the amount of interstate and intrastate pipeline that is needed to serve the repowered capacity. Alternatively, since the costs are averaged over all candidate plants based on gas volume delivered to the repowered site, it may approximate the diseconomies of scale that might arise in expanding compression or building new pipeline to serve only a limited amount of repowered capacity.

<sup>5</sup> A constant 1995 gas/coal price differential assumes that (1) end-use energy efficiency has an offsetting effect on increased utility gas consumption and/or (2) extraction/production costs for natural gas decline at the same rate as the increase in demand.

<sup>6</sup> The gas/coal price differential of \$0.72/MBtu represents the 1995 value as reported by EIA in its Annual Energy Outlook (AEO97). It represents a lower bound value, since the differential remains constant over time (and demand), reflecting no price response by the natural gas industry with increasing utility fuel demand. The \$1.18/MBtu reflects the 2010 gas/coal price differential within AEO97. This differential reflects a real natural gas price increase of \$0.40/MBtu (\$2.04/MBtu in 1995 to \$2.44/MBtu in 2010) and a 1.9 TCF increase in utility gas demand.

<sup>7</sup> “Partial Repowering” is equivalent to the “no additional transmission cost” case.

<sup>8</sup> “Partial Repowering” is equivalent to the “no additional transmission cost” case.